Final Report

A STUDY OF POWER SYSTEM OPTIONS FOR THE SOUTHEASTERN UNITED STATES

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FOREWORD

The purpose of the research was to examine systematically, from a regional perspective, alternative systems for meeting long term electrical energy demands. The objective of the research was to determine the potential energy and cost savings which might be realized through multiple-use generation systems, through hybrid-fueled generation systems, and through optimal resolution of the centralization-decentralization issue.

The program was conducted for the National Science Foundation under NSF Grant SIA74-20662 by the Engineering Experiment Station of the Georgia Institute of Technology, assisted by the Georgia Power Company and its parent company, the Southern Company. An Overview Committee advised the research team, meeting twice to review progress and commenting on the interim report. Contributors to the research effort and members of the Overview Committee are listed on the next page.

The authors acknowledge the support of the National Science Foundation (and the encouragement and advice of Dr. Thomas R. Anderson, the original project manager, and Drs. Aly Mahmound and Richard Schoen, the succeeding project managers), the contributions of the other research participants, and the helpful advice of the members of the Overview Committee. However, this report does not necessarily reflect the views or policies of the National Science Foundation, of Georgia Tech, of the Georgia Power Company, or of members of the Overview Committee.

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I. INTRODUCTION

Background

Per capita consumption of electricity has increased at an annual rate of almost six percent over the past two decades, and projections indicate that it will continue to increase, perhaps at a faster rate. Concomitantly, the percentage of total U.S. energy consumed by electric utilities is projected to rise to 40% to 50% by 1985. Shortages of traditional fossil fuels are likely, and it is not clear that nuclear fuel can, or should, completely fill the gap created by these anticipated shortages. These facts and projections establish the need for a systematic examination of alternative systems for meeting long term electrical energy demands.

Certain approaches offer the potential for increased efficiency of fuel usage and lower cost of electricity to the consumer: hybrid-fueled generation systems, multiple use generation systems, and "optimum" centralization-decentralization generation systems. Because of potential impacts and special regional needs and resources, these approaches are best examined from a regional perspective. Electric power utilities typically have a prescribed geographical perspective and a relatively narrow interpretation of their mission; these result in a limited regional perspective and little study of potential regional approaches to reducing the energy required for electrical energy generation and transmission. Consequently, there is the need for an objective and practical study, broader in scope than electric utility perspectives yet utilizing utility plans, data and viewpoints as inputs, to evaluate on a regional basis these different approaches.

The purpose of this research project was to help determine the desirability of hybrid-fueled systems and multiple use systems for the southeastern United States and to examine the issue of centralized versus decentralized systems for this region. The results are expected to provide Federal, regional, state, and utility decision- and policy-makers with additional knowledge about the economics of particular non-conventional systems for the generation, transmission, and distribution of electrical energy in the Southeast.

The project was conducted by the Engineering Experiment Station of the Georgia Institute of Technology in cooperation with the Georgia Power Company and its parent organization, the Southern Company. The study includes analyses for the southeastern United States, the region including Tennessee, North and South Carolina, Florida, Georgia, Alabama, and Mississippi.

The results of the project include:

1) an evaluation of the appropriateness of hybrid and multiple-use systems for the southeastern U.S.,

2) a determination of the economic, land use, and other impact trade-offs involved in choosing between large, centralized electric power generation and smaller, decentralized, electric power generation for the southeastern U.S.,

3) documentation of the approaches used to establish (1) and (2) and documentation of how these approaches may be utilized in other, similar, regional studies, and

4) an established relationship between university researchers and electric utility planners and decision-makers which can extend beyond this research effort and can continue to be mutually beneficial and educational for both, presenting a broader perspective to the electric utility planners and communicating utility problems to the university researchers.

Project Overview

The project examined the issues of hybrid-fueled generation of electricity, centralization-decentralization, and multiple use systems for the southeastern United States. The program examined the costs and benefits of implementing non-conventional technologies relative to conventional electrical energy generation and transmission.

This report includes four major sections. The first section summarizes the approach utilized to compare the costs and benefits of conventional and nonconventional technologies. The next two sections describe the preliminary results of the analyses of solar-fossil hybrid fueled central power stations and of waste-fossil hybrid fueled generating plants. The analyses in this report are from a national welfare perspective and private investor viewpoint. The fourth section investigates the concept of multiple-use systems, tradeoffs between centralized and decentralized systems, and regulatory issues.

In addition to the major sections, this report includes two appendices. Appendix A provides a list of working papers (contained in Volume 2) each of which describes in more detail particular aspects of the research effort. Appendix B is a glossary intended to illustrate some of the terms used in the report.

II. APPROACH

Cost Benefit Analysis

The approach selected for addressing the research issues is based on cost-benefit analysis. Cost-benefit analysis is a method for evaluating the relative value, or worth, of a particular decision, policy, or course of action compared with other decisions, policies, or actions. The evaluation is based on economic measures of the value of a project, and, in general, these measures may consist of the benefit-cost ratio, the pay-back period, and Net Present Value.

For this research project, the issue of hybrid systems is structured as choosing between two decisions, or courses of action: the generation of electricity by conventional fossil systems versus the generation of electricity by hybrid (either solar-fossil or waste-fossil) systems. For convenience, the option of generating electricity by conventional fossil fueled systems is called the baseline scenario, and the option of utilizing hybrid systems rather than conventional systems is called the alternative scenario. Because the issue is structured as choosing between two options, the appropriate measure is the Net Present Value.

The Net Present Value (NPV) of a project is a single number representing the net benefits of all present and future resource flows, where future costs and benefits are discounted to account for the decreased value of a future benefit or cost. (For example, it is evident that one would prefer having $100 now rather than receiving $100 a year from now; having the $100 now permits its investment and its being productive for a year. If one is indifferent to \$100 now and \$110 a year from now, then one's discount rate is .10, or 10%.

A more precise formulation for the net present value (NPV) of a project having costs C and benefits B now and through H future time periods is

$$NPV = B_0 - C_0 + \frac{B_1 - C_1}{(1+d)} + \frac{B_2 - C_2}{(1+d)^2} + \dots + \frac{B_H - C_H}{(1+d)^H}$$

$$= \sum_{t=0}^{H} \frac{B_t - C_t}{(1+d)^t}, \quad \text{where} \tag{1}$$

B_t = benefit (positive resource flow) in time period t,

C_t = cost (negative resource flow) in time period t,

d = discount rate, and

H = time horizon (generally taken as the economic lifetime of the project.)

Evaluation of two projects, or scenarios, can be accomplished by computing the NPV of the resource flows for each of the projects, and the additional net benefits of one over the other can be calculated by subtracting the NPV of one from the NPV of the other. However, because the difference between the sums of two series is identical to the sum of the differences between the series, the net benefits of one project over another can be calculated by finding the NPV of the differences in costs and benefits between the two projects. In this research effort, this latter procedure was used: the NPV of choosing the alternative scenario over the baseline scenario is the NPV of the differences between the benefits and costs of the two scenarios. If the NPV of the difference between the benefits less costs of the alternative scenario and the baseline scenario is positive, then the alternative scenario is economically preferable to the baseline scenario. This calculation is expressed by the same formula as above:

$$NPV = \sum_{t=0}^{H} \frac{B_t - C_t}{(1+d)^t}, \quad \text{but now}$$

B_t = additional benefits of alternative scenario over benefits of baseline scenario in time period t_0 and

C_t = additional costs of alternative scenario over costs of baseline scenario in time period t.

<u>Choice of Analytical Perspectives</u>

As the analysis described above is performed, two questions must be resolved: (1) costs and benefits to <u>whom?</u>, and (2) what is the appropriate discount rate? The answers to these questions depend on who the decision maker is and on the purpose of the analysis. Not only must the problem be defined but also the decision context of the problem must be specified in order for the cost-benefit analysis to be performed.

For this project, three different perspectives initially were distinguished: (1) a national, or societal viewpoint, (2) a regional viewpoint, and (3) a private, or investor, viewpoint. There appeared to be virtually no significant differences in the regional and national viewpoints; consequently, the research effort includes an examination of only the societal and the private, or investor, perspectives. These two perspectives involve different costs and benefits and different discount rates, as discussed in the following paragraphs.

Determining Costs and Benefits. For a particular project and a particular decision context, two sets of individuals may be distinguished: a set, A, of individuals whose members will be affected by the project, and a set, B, for whom the project is being conducted. Normally, sets A and B will not be identical, and A will not be a subset of B. If this is the case, then externalities, impacts not included in an evaluation of the impacts on the set B for whom the project is intended, will exist.

The societal and private investor analyses differ in what benefits and costs are included in the analysis. For the comparison between the baseline scenario (conventional fossil-fueled generation of electricity) and the alternative scenario (hybrid-fueled generation of electricity), the set A may be defined as all those individuals who may be affected by the implementation of the alternative scenario; the set B may be defined as the utility owners and those served by the utility. The societal analysis includes as benefits and costs the impacts on set A (e.g., the impacts on the U.S. population); the private investor analysis includes those impacts on set B.

The societal analysis thus would include costs of air and water pollution (which would be viewed as externalities in the private investor analysis). The private investor analysis would include the costs of equipment required to meet pollution standards, but no additional pollution costs. However, the private investor analysis would include depreciation, interest, and taxes. These factors affect financing and cash flow and are important to the investor. However, in the societal analysis, they do not represent real net resource flows to or from the project and would be viewed as transfer payments and accounting considerations.

Determining the Discount Rate. For the societal analysis, the appropriate rate is the societal discount rate, representing the degree to which society as a whole is willing to give up present consumption for future consumption. Although considerable research and debate are evident, economists generally have concluded that calculating the social discount rate is not amenable to economic analysis alone. Moreover, there is no widely-accepted, "correct" rate to use in cost-benefit analyses. Some analysts have argued for rates as low as 0%; others have used the government loan repayment interest rate (e.g., 8.5%). For this project, a rate of 7% is used as a baseline rate, but other values are used to illustrate the effect of changing the discount rate.

For the private investor analysis, the appropriate discount rate is higher and is selected according to standards for the industry. Rates of return as high as 20% have been discussed, and the investor discount rate typically will be greater than 12%.

Definitions of Terms. Appendix B is a glossary of terms used in cost-benefit analysis. This list may be useful for clarifying particular concepts and phrases which otherwise are not clearly defined in the report.

III. SOLAR-FOSSIL HYBRID SYSTEM

The use of the sun's radiation is not new, but solar energy as part of a long term answer to the energy problem is receiving increasing interest. It is being viewed as a renewable, nonpolluting resource which offers the potential to furnish a significant fraction of the country's energy needs. Although it is abundant, solar energy is dispersed and its utilization requires that it be collected and concentrated.

The many approaches to collecting and concentrating solar energy may be classified into two categories:

1) The flat plate collector uses an absorbing surface equal in area to the total area of the collector. This type of collector operates on direct as well as diffuse radiation. Its advantage is that it is stationary and relatively inexpensive. The flat plate collector is used on a small scale, e.g., in residential units. Usually the collector is on the roof of the building with its associated piping beneath the absorbing surface. As illustrated in Figure 1 this type of collector can achieve temperatures up to 200°F.

2) The focusing collector uses mirrors or other curved or flat reflective surfaces to concentrate the direct component of the sun's radiation onto a heat exchanger smaller than the projected area of the collector, thus achieving higher energy flux. The focusing collector is extremely expensive due to the support mechanism (tracking devices). The CNRS solar furnace in France as well as the solar boiler superheater in Italy are examples of focusing collectors. As illustrated in Figure 1 this type of collector can achieve temperatures around 7,000°F. The focusing collector category consists of two main concepts: a central receiver system and a distributive system.

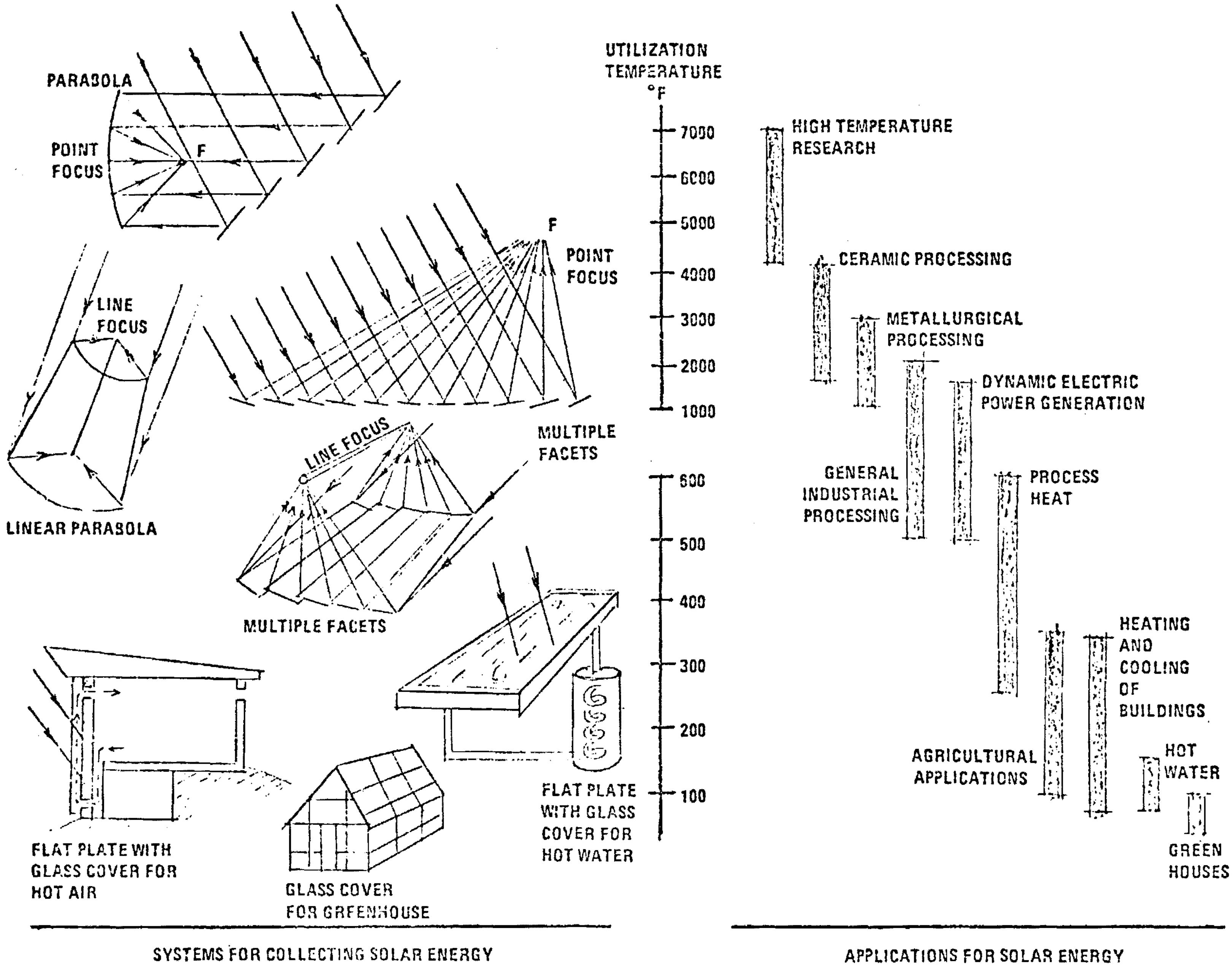


FIGURE 1. SYSTEMS FOR COLLECTING SOLAR ENERGY AND APPLICATIONS FOR SOLAR ENERGY AS A FUNCTION OF UTILIZATION TEMPERATURE. (Ref. 1, p. 5).

The Central Receiver System utilizes a large number of heliostats (mirrors plus tracking devices) to direct the sun's radiation onto a receiver (usually a large boiler) located on top of a tower (Figure 2A). Each heliostat can be rotated on two axes to enable it to track the sun's radiation throughout the day and year. The energy absorbed at the receiver is transferred to a fluid and transported to a turbine/generator for conversion to electrical energy or to storage for later use.

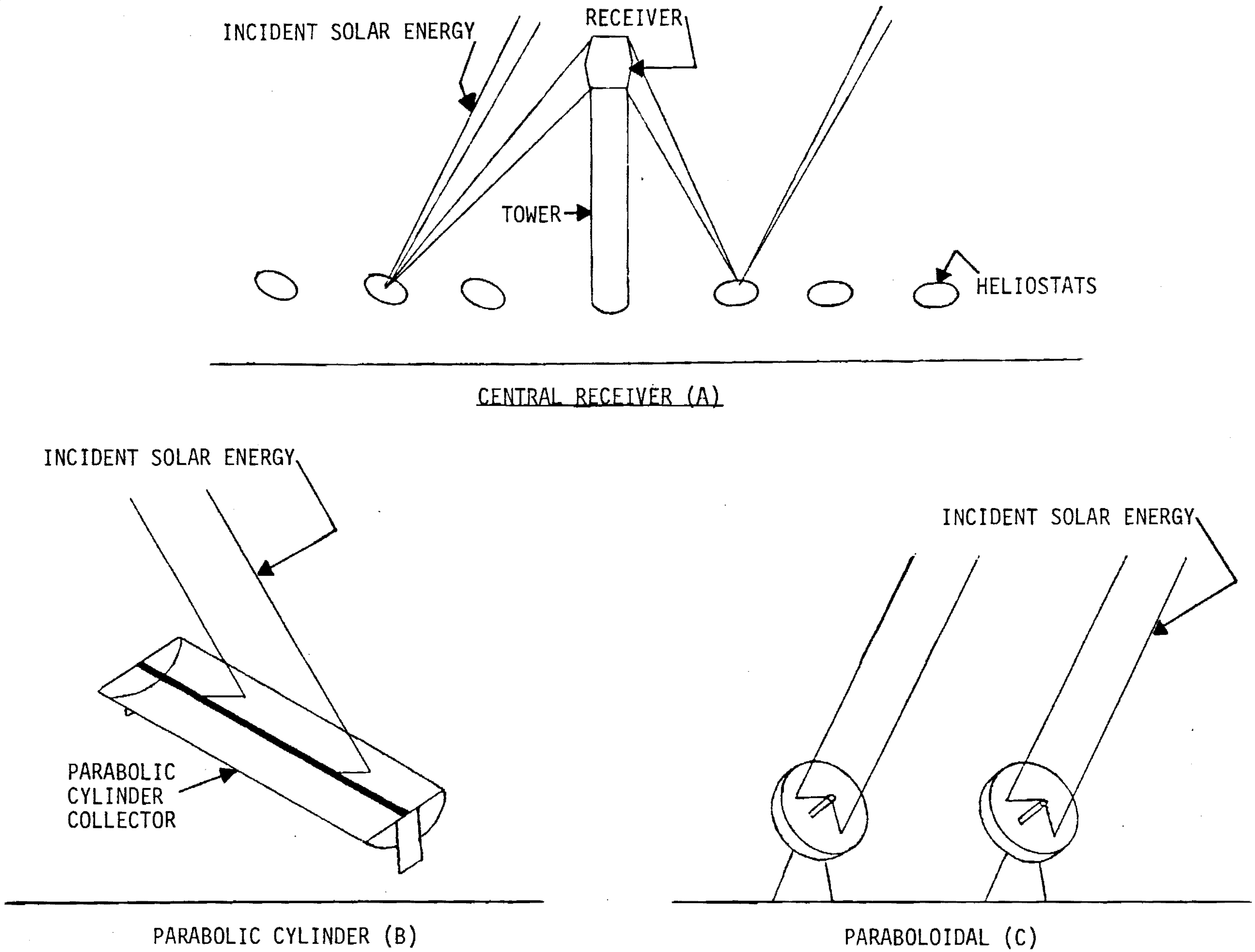
The Distributive System consists of a large number of small collectors (Figure 2B-2C) which convert the solar insolation to thermal energy. This system requires long pipe lines to collect and transport the heated fluid to the turbine/generator or central storage. Because of the large amount of piping and thermal loss in transport, this system is not so economical as the central receiver system.

Postulated System

This study examines a solar energy augmented fossil fuel electric power plant (solar-fossil hybrid plant) formed by retrofitting solar hardware to an existing fossil fuel plant. The basic design and size for the plant were selected after reviewing the literature.

Skeldahl, Inc., analyzed seven possible methods of utilizing solar energy as direct thermal input in a solar-fossil fuel system (Ref. 3, Chap. 8). Based on the results of this study, the preferred design is a separate solar-heated steam boiler which augments the output of superheated steam from the fossil boiler. Advantages to this solar input mode are:

1) there is a minimal amount of modification of the existing fossil facility,
2) independent operation of the fossil plant may resume whenever desired,



DISTRIBUTIVE SYSTEM

Figure 2. Central Receiver and Distributive Systems

3) the solar input to the hybrid system is not limited by the interaction of the fossil boiler section.

The disadvantages of this concept are:

1) a separate system for control of steam generation in the solar boiler is required,

2) a relatively complex and expensive central receiver collector system is also needed in order to efficiently attain high steam temperatures.

A preliminary study by McDonnell Douglas indicates the optimum power plant size is about 300 MW (Ref. 4, p. 275). Based on this study, the postulated solar fossil hybrid plant consists of a 300 MW fossil facility interfaced with a 100 MW solar boiler. The solar capacity decision was based on the following:

1) A study performed by Aerospace Corporation indicates the economies of scale within the 100-500 MW range are insignificant. The benefits resulting from the larger turbine generator plant size are offset by the increase piping cost incurred in connecting the additional solar hardware to the central turbine generator (Ref. 5, pp. 203-4).

2) A similar study done by Colorado State University indicates the least cost of electric power is obtained when the tower/heliostat system is within the 100-300 MW range (Ref. 6).

3) Officials at Georgia Power Company indicate that a fossil boiler has a recovery rate of 5 MW/min. Assuming a thirty minute storage capacity, the solar facility should be no larger than 150 MW. If a larger storage system is assumed, the solar unit can be increased to a maximum of 200 MW. At this capacity, the existing fossil boilers would be operating at only 30% of their capacity—the lowest practical limit that can be maintained with a "recovery" rate of 5 MW/min.

In the above discussion, the solar facility is limited to 150 MW when one assumes a 300 MW power plant and a thirty minute storage capacity.

For this study a 100 MW solar facility was proposed, based on a study by Aerospace Corp. (Ref. 2, p. 182).

A central receiving system similar to Figure 2A is postulated. Based on a study by McDonnell Douglas (Ref. 7, p. 198), the optimal heliostat size with respect to total system cost is approximately $23m^2$. Using this size heliostat (4.8m x 4.8m surface), the collector field consists of 50,517 heliostats requiring approximately 1.2 Km^2 of collector area. At a 38.6% land utilization (Ref. 2, p. 213) (i.e., 38.6% of the land is covered by collector surface) a total land area of 3.0 Km^2 would be required.

The central receiver station is placed at the southern edge of the collector field, since the north field heliostats are optically more effective (see Ref. 8, p. II-26 for a detailed geometric description of this statement). The postulated station consists of one, large 216 m tower, as a single tower is more economical and provides less heat loss than several smaller towers (Ref. 7, p. 30). Shading and blocking (due to tilting of the heliostats), and other reflector associated energy losses are minimized if the ratio of tower height to reflector diameter is approximately 45 to 1 (Ref. 9, p. 166).

Solar heat may be stored by raising the temperature of inert substances such as water or rocks. Although this method requires a large amount of space, it is the least costly. As indicated earlier, a 30 minute thermal storage capacity is assumed (Ref. 2, p. 185).

Statement of the Problem

The objective of this part of the study is to determine the conditions for which the postulated solar-fossil hybrid system is economically feasible. The methods and procedures, based on cost benefit analysis, are described in Chapter II, APPROACH.

The baseline, or status quo, scenario is assumed to be the generation of electric power by conventional techniques (primarily fossil fueled, nuclear fueled, and hydroelectric plants). The alternative scenario includes the generation of electric power by solar-fossil hybrid systems.

The present value of the differences in costs and benefits between the alternative and the status quo scenarios is used as the measure of economic feasibility. If the present value of the difference in net benefits is positive (net benefits of the alternative scenario exceed the net benefits of the status quo scenario), the solar-fossil hybrid system is judged to be economically feasible.

The primary cost difference between the scenarios is the investment costs required to implement the solar energy components of the hybrid system. The primary benefit difference between the scenarios is the lower operational costs in the alternative scenario due to the reduced requirement for fossil fuel.

Technical Parameters

The differences between the two scenarios depend on two sets of technical parameters: solar energy system parameters and conventional system parameters. Table 1 lists the solar energy parameters and shows for each the range of probable values and the most likely value. The column labelled "symbol" indicates the parameter name used in the computer model.

The conventional system parameters are those associated with the baseline scenario, which assumes the continuation of conventional electric power generation. Because the primary benefit difference between the scenarios is the reduced fossil fuel requirement, the analysis requires data only on fossil fuel plants.

Table 1. Solar Energy System

Symbol	Parameter (dimension)	Probable Range	Most Likely Value
ASI	Average Annual Solar Insolation (W/M^2)	560-640[7]	600[1]
HS	Annual Hours of Usable Energy	2600-3000[8]	2800[1]
STE	Solar-Thermal Efficiency(%)	60-62[2]	60[3]
TEE	Thermal-Electric Efficiency (%)	30-35[2]	35[3]
SFL	Life of Solar Facility (Years)	20-40[4]	30[5]
SIZE	Size of Solar Facility (MW)		100[6]
FHR	Fraction of Hour Needed for Storage		.5[6]

1. Represents midpoint of given range
2. Ref. 10 (p.49); 8 (pp. II-13 and II-8); 2 (p. 149)
3. Most common value in the literature
4. Arbitrarily chosen
5. Ref. 2 (p. 161)
6. See discussion in previous section, Postulated System
7. Ref. 17 (pp. 24-52)
8. Ref. 1 (p. 61)

In the southeastern states, seven different combinations of fossil fuel processes exist for generating electricity. They are:

1. coal-fired steam
2. oil-fired steam
3. gas-fired steam
4. oil-fired turbine
5. gas-fired turbine
6. oil-fueled internal combustion
7. gas-fueled internal combustion

Table 2 shows the total electrical energy produced and fuel consumed for each of these processes. Based on the values in Table 2 and on FPC data (Ref. 14, pp. 16, 22, 26), the average cost of fossil fuel in the southeastern United States was derived. Table 3 shows these costs.

Besides the parameters associated with fuel cost, quantity, and process efficiency, the analysis also considers the parameters associated with pollution control cost. Table 4 lists fuel and air pollution parameters and gives a range of probable values and the most likely value for each.

Economic Parameters

The economic parameters consist of the various cost involved in retrofitting the existing fossil plant with the solar facility. The basic and most costly item of equipment is the collector. This includes the mirrors, heliostat fabrication and installation, tracker control and drive equipment. The receiver, consisting of the tower, boiler and superheater, boiler monitor and control instrumentation, steam and feedwater piping, also constitutes a large percentage of the initial capital cost.

Besides the capital cost, there also exists the annual maintenance cost. This includes the cost of cleaning, repairing and replacing the reflectors as well as servicing the other equipment.

Table 2.

ELECTRICAL ENERGY PRODUCTION AND FUEL CONSUMPTION, 1974
(Southeastern United States: Tennessee, North and South Carolina, Georgia, Florida, Mississippi, Alabama)

PROCESS	FUEL QUANTITY	ENERGY CONSUMED (BTU)	ENERGY PRODUCED (KWH)	ENERGY PRODUCED (PERCENT)		EFFICIENCY (PERCENT)
STEAM	8.110×10^7 TONS OF COAL	1.885×10^{15}	1.856×10^{11}	57.1		33.6
	8.582×10^7 BBLS OF OIL	5.349×10^{14}	5.106×10^{10}	15.7	79.4	32.6
	2.424×10^8 MCF OF GAS	2.482×10^{14}	2.161×10^{10}	6.6		29.7
NUCLEAR			2.527×10^{10}		7.8	
TURBINE	8.713×10^6 BBLS OF OIL	5.431×10^{13}	3.648×10^9	1.1	1.6	22.9
	2.321×10^7 MCF OF GAS	2.376×10^{13}	1.499×10^9	.5		21.5
INTERNAL	4.531×10^5 BBLS OF OIL	2.824×10^{12}	2.359×10^8	.07	0.1	28.5
COMBUSTION	1.890×10^6 MCF OF GAS	1.935×10^{12}	1.753×10^8	.05		30.9
HYDROELECTRIC			3.626×10^{10}	11.1	11.1	

(Ref. 11, pp. 22, 13-16; Ref. 12, pp. 12, 16, 22, 26).
(Ref. 13, Appendix E, pp. 285-287).

Table 3. Average Cost of Fossil Fuel (\$/KWH) in Southeastern United States (Dec. 1974)

Process (ℓ)	A	B	(A)(B)
Steam			
Coal	70.4	.0106	.746
Oil	19.4	.0175	.340
Gas	8.4	.0094	.076
Turbine			
Oil	1.4	.0249	.035
Gas	.6	.0130	.008
Internal Combustion			
Oil	.09	.0200	.002
Gas	.06	.0091	.0005
TOTAL			1.2075
AVERAGE FOSSIL FUEL COST (\$/KWH)			.012

(A) % of fossil fuel generated electricity = $\frac{f_\ell}{1-f_o} \cdot (100)$

f_o = fraction of electricity generated by nuclear and hydro = .189

f_ℓ = fraction of total electric power generated by "ℓ" process

(B) Fuel Cost (\$/KWH) = $\frac{\text{fuel cost (\$/MBTU)}}{(293.1)^{*}\ \text{efficiency}}$

Fuel Costs are based on Dec. 1974 prices: (Ref. 14, pp. 16, 22, 26).

Coal \$1.04/MBTU

Oil \$1.67/MBTU

Gas \$ .82/MBTU

*If system were 100% efficient, 1 MBTU = 293.1 KWHe

Table 4. Fuel and Pollution

Symbol	Parameter (dimension)	Probable Range	Most Likely Value
FC	Fuel Cost— Coal ($/MBTU)	---	1.00[1]
EFF	Efficiency of Coal— Burning Power Plant	---	.336[2]
SCP	Social Cost of Pollution ($/ton of SO_2 emissions)	---	7.30[3]
EMIS	Tons of Pollutant/MBTU of Fuel Burned	.002-.004[4]	.003[5]

1. Calculations from data found in Ref. 16, (p.29).
2. See Table 2.
3. See details in Working Paper IV.
4. See details in Working Paper IV.
5. Represents midpoint of range, for SO_2 pollutant assuming 2.5% sulfur content.

Table 5 lists the economic parameters and indicates for each parameter a range of probable values and the most likely value.

Table 5. Economic Parameters

Symbol	Parameter (dimensions)	Probable Range	Most Likely Value
CC	Cost of Collector ($\$/M^2$)	26-35[1]	30[2]
CA	Cost of Acre of Land	0-3000[3]	0[4]
CS	Cost of Storage ($/KWH)	15-38[5]	15[7]
CR	Cost of Receiver ($/KW)	68-71[6]	70[3]
CI	Cost of Insurance and Local Taxes (% of Capital Cost)	---	1.5[8]
OMC	Operation and Maintenance Cost ($/KW)	2.54-4.80[9]	3.50[10]
SDR	Social Discount Rate (%) (used in National Welfare Analysis)	5-10[11]	7[10]
DR	Discount Rate (%) (used in Private Investor's Analysis)	10-15[12]	12.5[10]
I	Interest Rate (%)		8.5[13]

1. Ref. 2 (p. 184) 7 (pp. 7,9).
2. Ref. 2 (p. 185—Chart 85).
3. Arbitrarily chosen.
4. Conversation with Charles Minors of Georgia Power Company.
5. Ref. 2 (p. 185—Chart 85); 15.
6. Ref. 2 (p. 185—Chart 85); 11 (p. 13).
7. Most frequent number found in the literature.
8. Conversation with Al Fosser of Aerospace Corp., 1975.
9. Ref. 8 (p. V-3); 9 (p. 135).
10. Approximate midpoint of range of values in the literature.
11. Although the social discount rate cannot be determined strictly by economic analysis, it is generally considered to be within the range of five to ten percent. The NASA-Wind Power Study uses five percent (Ref. 13, p. 214).
12. Range of current discount rates.
13. Based on current rates for AAA and AA rated companies.

Analyses and Results

The parameters discussed above were included in a set of equations representing their relationship to one another and to the other variables in the model. The equations are written from the national welfare perspective; minor changes are necessary to represent the private investor viewpoint.

The annual benefits of operating the solar-fossil plant (net benefits above the benefits of a conventional plant) are given by

$$B = V + CP - OC \tag{2}$$

where OC is the additional annual operating cost of the solar plant, V, the value of the fuel saved annually is defined by

$$V = \frac{(FC)(SIZE)(HS)}{(293.1)(EFF)}, \text{ and} \tag{3}$$

CP, the annual cost to society of pollution from burning fossil fuel is defined by

$$CP = \frac{(SCP)(EMIS)}{(293.1)(EFF)} \times (SIZE)(HS) \tag{4}$$

(In these and the following equations, the parameters are defined in Tables 1, 4 and 5; they are summarized in Table 6, below).

Additional costs of the solar plant reduce the benefits; these costs are calculated by

$$OC = (OMC)(SIZE) \tag{5}$$

The capital cost in the NPV equation is represented by

$$C = \left[\frac{(1000)\ (CC)}{(TDR)(STE)(TEE)} + \frac{(ANUM)(CA)}{(.386)(SIZE)} + \frac{(CR) + (CS)(FHR)}{1}\right] SIZE \tag{6}$$

Table 6. Summary of Parameters with Their Baseline Values

Symbol	Parameter (dimension)	Baseline Value
CC	Collector Cost ($\$/m^2$)	30
CA	Cost of Acre of Land	0
CS	Cost of Storage ($/KWH)	15
CR	Cost of Receiver ($/KW)	70
CILT	Cost of Insurance & Local Taxes (% of Capital Cost)	1.5
OMC	Operating and Maintenance Cost ($/KW)	3.50
SDR	Social Discount Rate (%)	7
DR	Discount Rate (%)	12.5
I	Interest Rate (%)	8.5
ASI	Average Annual Solar Insolation (W/m^2)	600
HS	Annual Hours of Usable Energy	2800
STE	Solar-Thermal Efficiency (%)	60
TEE	Thermal-Electric Efficiency (%)	35
SFL	Life of Solar Facility (years)	30
SIZE	Size of Solar Facility (MW)	100
FHR	Fraction of Hour Needed for Storage	.5
FC	Fuel Cost-Coal	1.00
EFF	Efficiency of Coal-Burning Power Plant	.336
SCP	Social Cost of Pollution ($/ton of SO_2 emissions)	7.30
EMIS	Tons of Pollutant/MBTU of Fuel Burned	.003

where TDR, the total direct radiation is defined by

$$TDR = .68(ASI) \tag{7}$$

and ANUM, the number of acres of collectors is defined by

$$ANUM = \frac{(.246)(SIZE)}{(TDR)(STE)(TEE)} \tag{8}$$

A computer program to calculate these benefits and costs was written and debugged. The program was then used to perform sensitivity and parametric studies.

As discussed in Chapter II, for this project two different perspectives were distinguished: (1) a national, or societal viewpoint, and (2) a private, or investor viewpoint. This section will first summarize the results from a national perspective, followed by the analysis from the investor's perspective.

National Welfare. The NPV and net benefits of solar energy are summarized in Table 7 for the southeastern United States. Row one values are based on a static price of coal, row two values are based on a price that annually increases by one percent above the inflation rate, while row three values are based on a price that annually increases by 2.5 percent above the inflation rate. Under the first two conditions, it is not economically feasible to retrofit an existing coal facility with solar hardware; however, when the fuel price is assumed to increase by 2.5 percent annually the production of electricity by means of solar energy would be economically feasible, producing a net benefit of $2,641,310 over the life of the facility.

The sensitivity analyses examined the impacts (on the Net Present Value of SFFHS) of changes in collector cost, fuel cost, average annual

Table 7. National Welfare Analysis—Net Present Value and Net Benefits of Solar Energy for Southeastern United States

	Net Present Value	Net Benefits of Solar Energy ($/KWH)
Static Fuel Price	-$11,053,493	-.0032
1% Annual Fuel Price Increase	-$ 4,608,968	-.0013
2.5% Annual Fuel Price Increase	$ 2,641,310	.0008

NOTE: Capital Cost for all Scenarios = $42,764,006 solar insolation, annual hours of usable energy, the lifetime of the solar facility, and the social discount rate. The relationships are shown in Figures 3 through 8.

The first influencing factor is the cost of the collector. Figure 3 illustrates that when the cost of the collector decreases to $20/m^2 or less, the cost of producing electricity by solar energy will be at least competitive with existing conventional systems. Figure 4 represents the net present value of SFFHS as a function of fuel cost. This graph illustrates that when the price of fuel rises to $1.32/MBTU, the benefits of solar energy will outweigh the additional investment. If one were to relax the assumption of a coal-only economy and consider an economy similar to today's (i.e., the average price of fossil fuel is $1.14/MBTU in the southeastern states and $1.41/MBTU in Florida), then generating electricity by means of solar energy becomes more nearly economically feasible in the southeastern states and is actually advantageous in Florida. It is interesting to note that the parameter to which the model is most sensitive (fuel cost) is the one most likely to change in the near future.

If all the baseline values were held constant and the average annual solar insolation varied within its range for the southeastern states (550-640 W/m^2), Figure 5 illustrates that solar energy would not be competitive with existing means of generating electricity. However, an increase in solar insolation often is accompanied by an increase in the annual hours of sunshine. In the Miami area, the annual average insolation is 640 W/m^2 and the total number of annual hours of sunshine is 3000. If we replace the baseline value of 2800 hours in the model with 3000 hours, the net present value of a SFFHS would increase from -$8,865,118 to -$457,431. This is still economically infeasible, but it would take only a $.02/MBTU increase in the cost of fuel to reach the break-even point.

Figure 3. Influence of Collector Cost on Net Present Value of SFFHS (National Welfare Analysis)

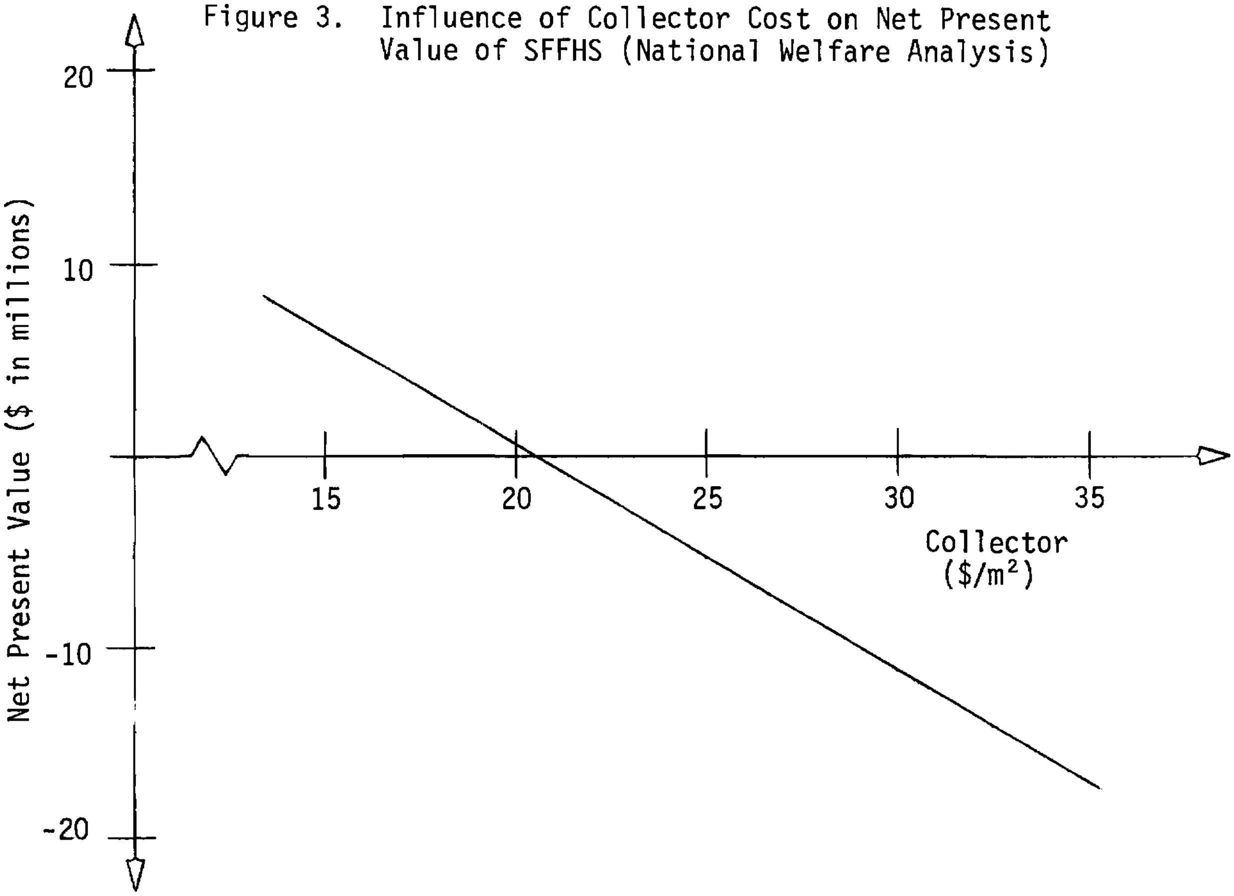


Figure 4. Influence of Fuel Cost on Net Present Value of SFFHS (National Welfare Analysis).

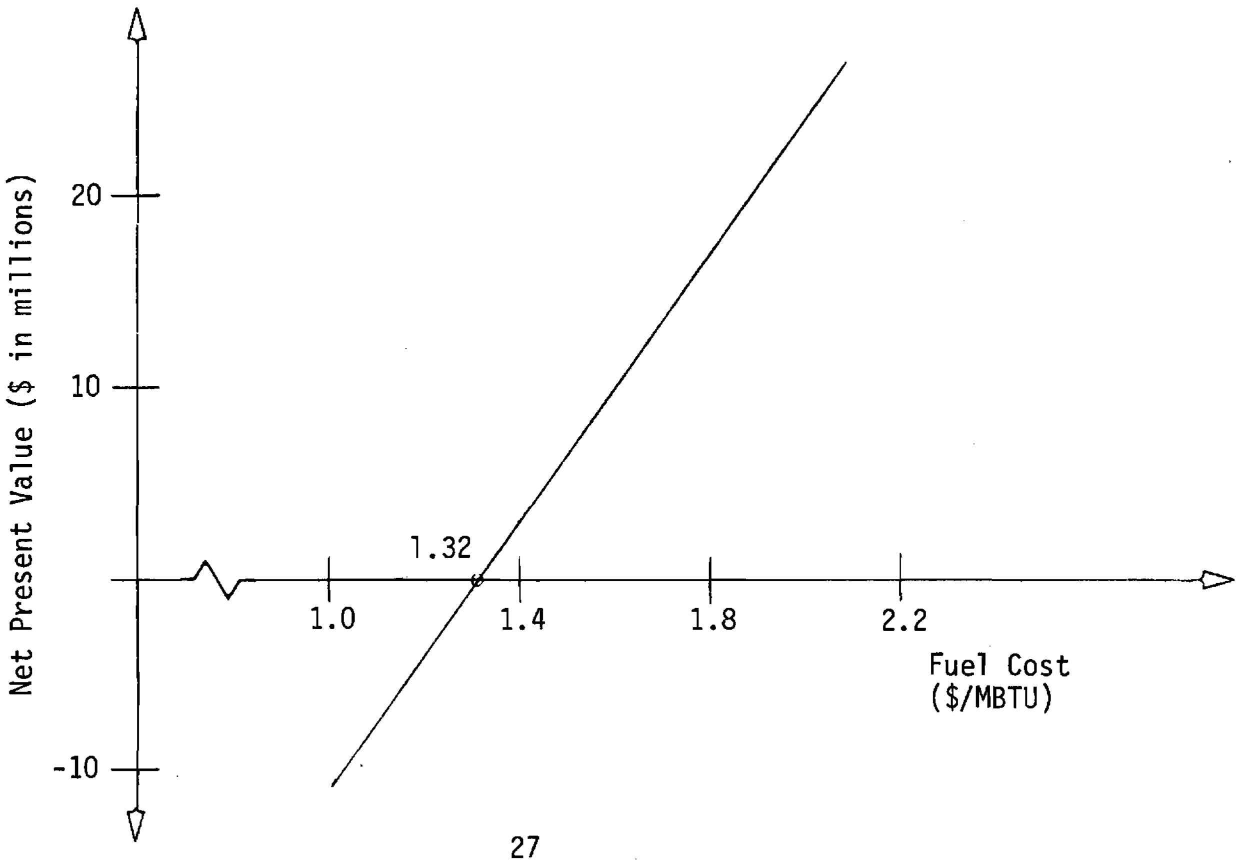


Figure 5. Influence of Annual Solar Insolation on Net Present Value of SFFHS (National Welfare Analysis)

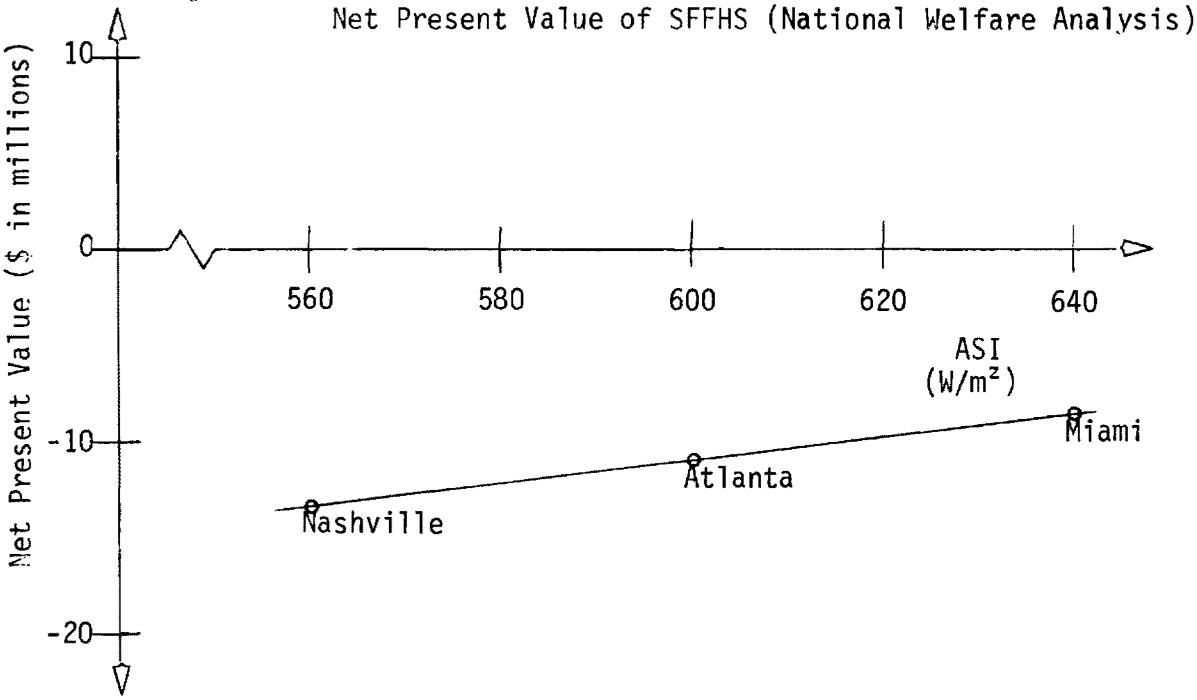


Figure 6. Influence of Annual Hours of Sunshine on Net Present Value of SFFHS (National Welfare Analysis).

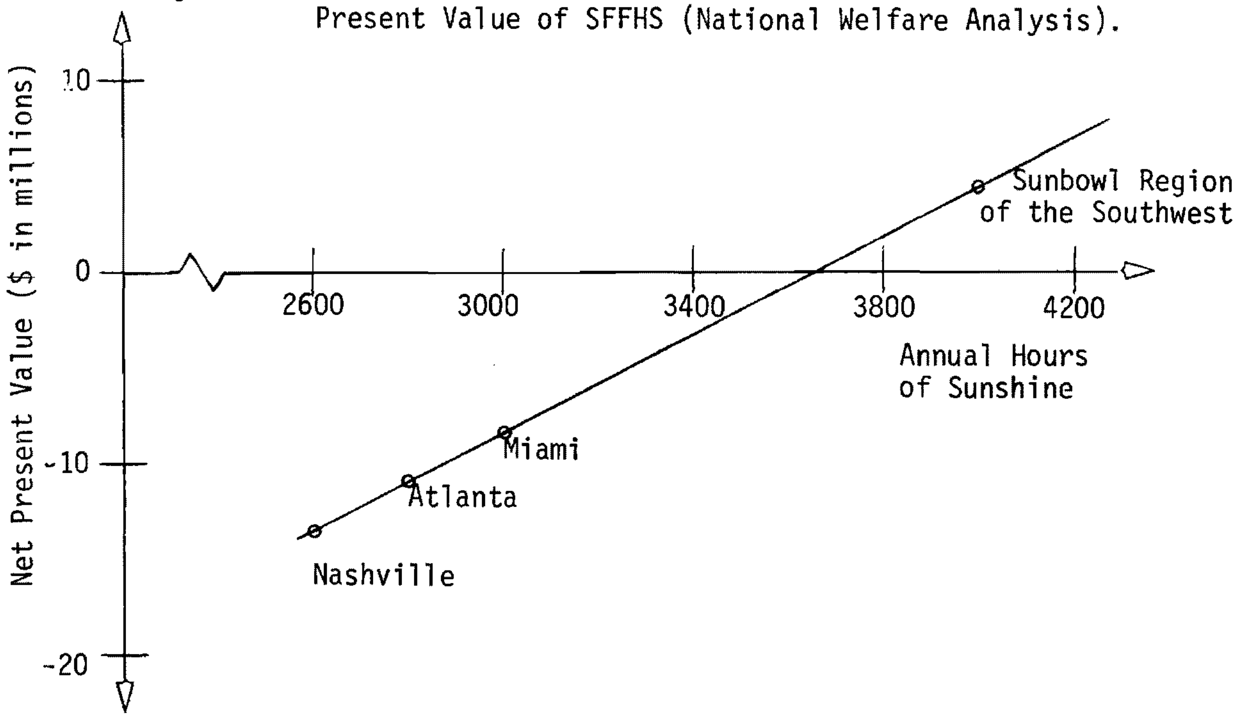


Figure 6 represents the net present value of a SFFHS as a function of annual hours of usable energy. This graph illustrates that when the number of hours of sunshine is greater than about 3660 hours, the net benefits of solar energy would be positive (i.e., the solar-fossil hybrid system is economically desirable).

The influence of a solar facility's expected useful life on the net present value of a SFFHS is represented in Figure 7. This graph indicates that when the facility's lifetime is increased from 20 to 60 years, the net benefits of solar energy increase but still remain negative.

Figure 8 represents the net present value of a SFFHS as a function of the social discount rate. This graph illustrates that when the social discount rate is approximately four percent (or less), the benefits of solar energy outweigh the additional investment.

Several locations have been arbitrarily chosen as representative of southeastern United States for a parametric study. For each location three scenarios were analyzed and the results are tabulated in Table 8. Columns five and six are based on a static price of coal and indicate in all five locations it is not economically feasible to retrofit an existing coal plant with a solar facility. Columns seven and eight are based on the price of coal annually increasing by one percent above the inflation rate and indicate it is advantageous to generate electricity using a SFFHS in Miami, Florida, primarily due to the high cost of coal in this region coupled with the high solar insolation and annual hours of sunshine. Column nine and ten are based on the price of coal annually increasing by 2.5 percent above the inflation rate and indicate it is advantageous in four of the five locations chosen (Miami, Atlanta, Raleigh, Charleston). A SFFHS remains economically infeasible in Nashville, Tenn., primarily due to the low cost of coal in this region.

Figure 7. Influence of Life of Facility on Net Present Value of SFFHS (National Welfare Analysis).

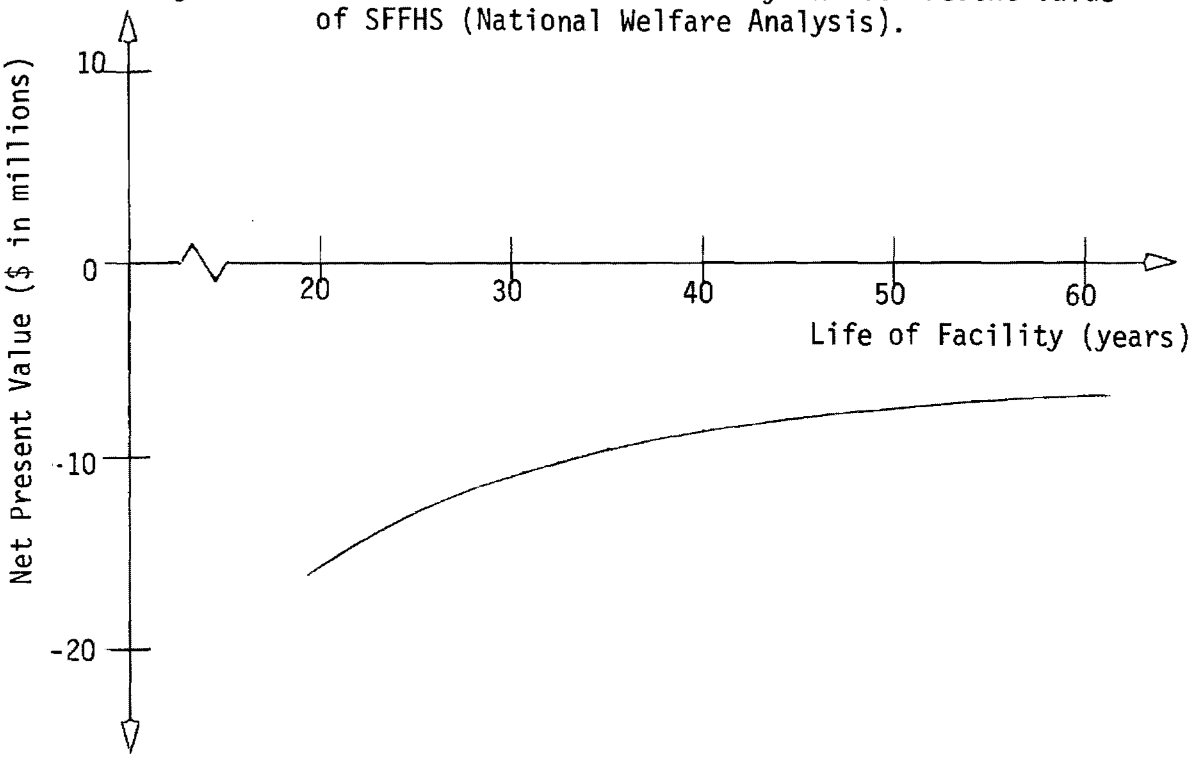


Figure 8. Influence of Social Discount Rate on Net Present Value of SFFHS (National Welfare Analysis).

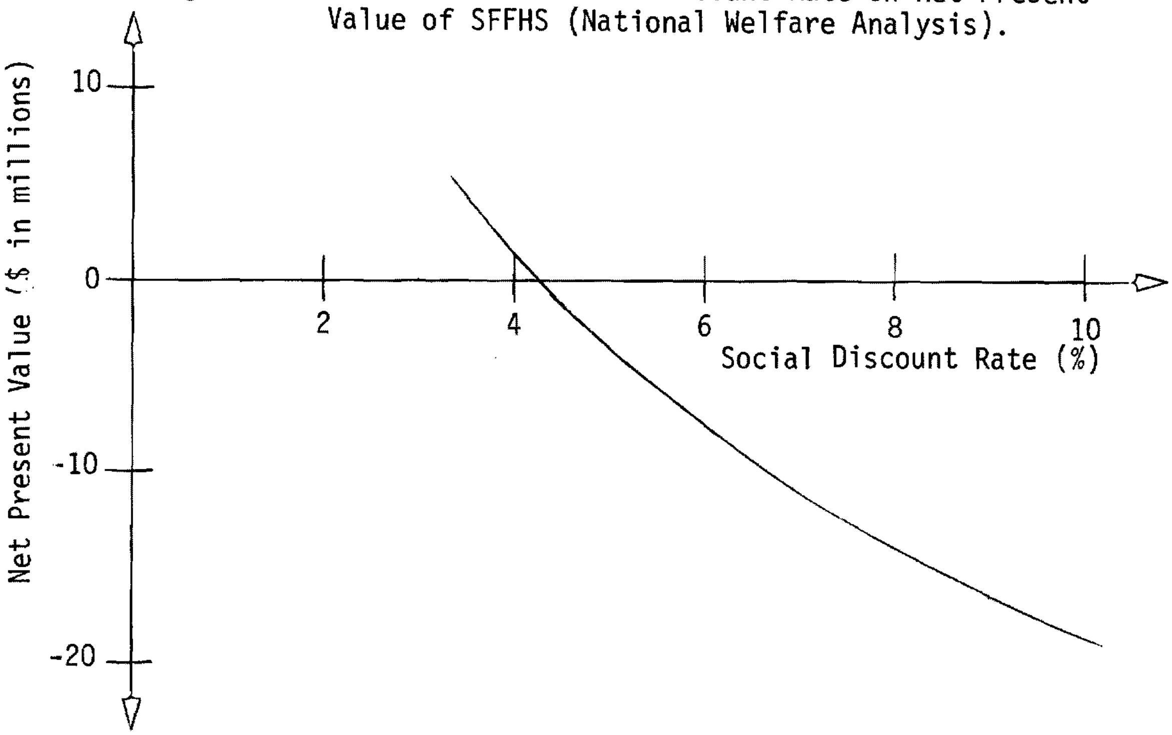


Table 8. Site Analysis for National Welfare

	ASI W/m^2	Sun-shine Hours	Coal Price* $/MBTU	Eff of Coal Plants	Static Price: Net Present Value ($)	Static Price: Net Benefits $/Kwh	1% Annual Fuel Price Increase: Net Present Value ($)	1% Annual Fuel Price Increase: Net Benefits $/Kwh	2.5% Annual Fuel Price Increase: Net Present Value ($)	2.5% Annual Fuel Price Increase: Net Benefits $/Kwh
Miami, FL	641	3000	1.09	.318	- 457,431	-.0001	7,494,868	.0020	16,441,440	.0044
Atlanta, GA	598	2800	.97	.335	-12,124,564	-.0035	-5,854,715	-.0017	1,199,049	.0003
Raleigh, NC	629	2600	1.07	.358	-11,919,430	-.0037	-5,909,821	-.0018	851,165	.0003
Charleston, SC	613	2800	1.08	.345	- 8,502,623	-.0024	-1,724,105	-.0005	5,901,928	.0017
Nashville, TN	561	2800	.93	.324	-14,713,441	-.0042	-8,498,055	-.0024	- 1,505,563	-.0004

*December 1975 fuel prices

Private Investor. The private investor's analysis differs from the national welfare analysis in five areas. First, the businessman usually does not have the available resources to invest in a solar facility; therefore he needs to decide on ways to finance the investment. In the computer interactive program a choice is given with regard to the method of financing: issuing bonds or borrowing; the user then is instructed to state the interest rate and the length of time for financing the debt. Second, depreciation on the capital equipment is taken into consideration. Here again a choice is given as to which method of depreciation is to be used: straight-line or sum of years digits. Also,the lifetime of the asset needs to be stated. Third, the discount rate used to determine the rate of return on the investment is higher than the rate used in the national welfare analysis. Fourth, the annual operating cost includes not only the cost incurred to operate and maintain the facility but also the cost of insurance, local taxes and interest on the debt. Fifth, the cost of pollution to society is not taken into account. In this analysis, issuing bonds at 8.5% for 30 years to finance the debt and a straight-line depreciation of the capital equipment for 30 years was chosen.

Table 9 summarizes the NPV and net benefits of solar energy for the southeastern United States. Row one values are based on a static price of coal, row two values are based on a price that annually increases by one percent above the inflation rate, while row three values are based on a price that annually increases by 2.5% above the inflation rate. Under all three conditions, it does not appear economically feasible to retrofit an existing coal facility with solar hardware.

The sensitivity analysis for the private investor sector examined the impacts (on the net present value) of changes in collector cost,

Table 9. Private Investor Analysis—Net Present Value and Net Benefits of Solar Energy for Southeastern United States

	Net Present Value	Net Benefits of Solar Energy ($/KWH)
Static Fuel Price	-$15,098,065	-.0069
1% Annual Fuel Price Increase	-$10,460,347	-.0048
2.5% Annual Fuel Price Increase	-$ 7,152,808	-.0033

NOTE: Capital Cost for all Scenarios = $42,764,006 fuel cost, average annual solar insolation, annual hours of usable energy, lifetime of the solar facility, and the social discount rate. The relationships are shown in Figure 9 through 14.

The first influencing factor is the cost of the collector. Figure 9 illustrates that when the collector cost decreases to $13/m^2 or less, the cost of producing electricity by solar energy will be at least competitive with existing conventional systems. Figure 10 represents the net present value of a SFFHS as a function of fuel cost. This graph illustrates that when the price of fuel rises to $1.69/MBTU, the benefits of solar energy will outweigh the additional investment. Although the $1.68/MBTU price of fuel is high relative to today's coal prices, in the southeastern United States the average price of oil was $1.70/MBTU in March 1976 and averaged $1.68/MBTU for the first quarter of 1976.

In Figures 11 and 12 the range of values for the average annual solar insolation and annual hours of usable energy in the southeastern United States are plotted. The figures illustrate that throughout the Southeast there are no regions that can generate electricity by a SFFHS so economically as the status quo scenario given the baseline values assumed.

The influence of a solar facility's expected useful lifetime on the net present value of a SFFHS is represented in Figure 13. This graph illustrates for the private investor analysis that the net present value is relatively insensitive to a facility's lifetime beyond 20 years. The net present value increases only $2 million (from -$16 to -$14 million) when the lifetime is extended from 20 to 60 years.

Figure 14 represents the net present value of a SFFHS as a function of the discount rate. As the discount rate increases, the NPV will increase but remain negative. However, it cannot be assumed that given

Figure 9. Influence of Collector Cost on Net Present Value of SFFHS (Private Investor Analysis).

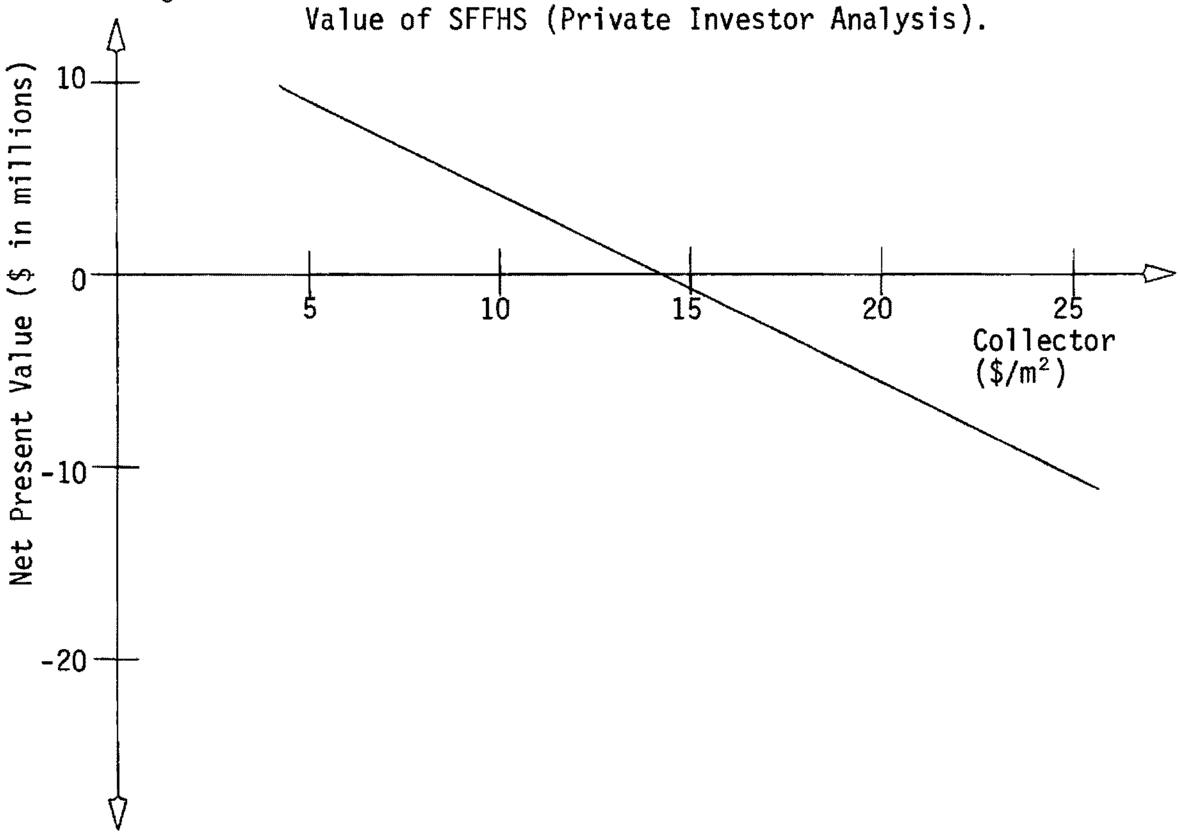


Figure 10. Influence of Fuel Cost on Net Present Value of SFFHS (Private Investor Analysis).

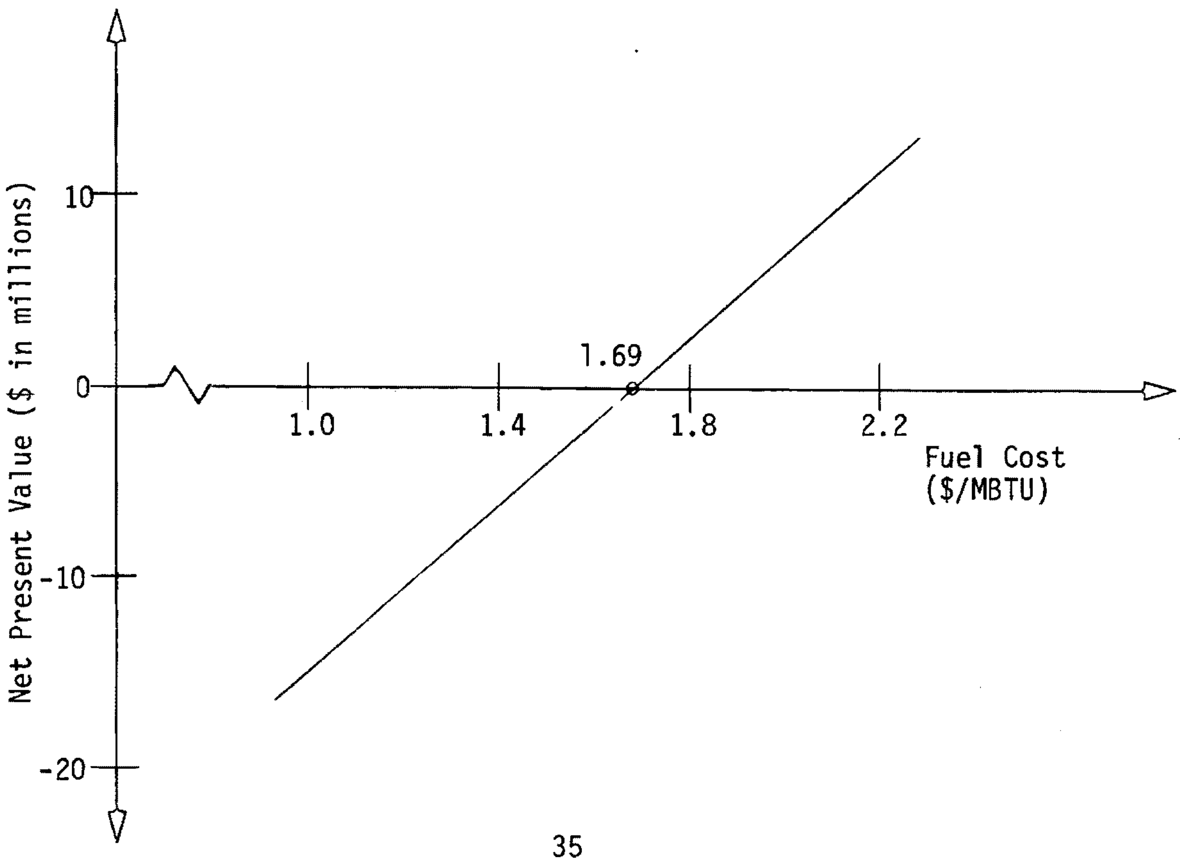


Figure 11. Influence of Annual Solar Insolation on Net Present Value of SFFHS (Private Investor Analysis).

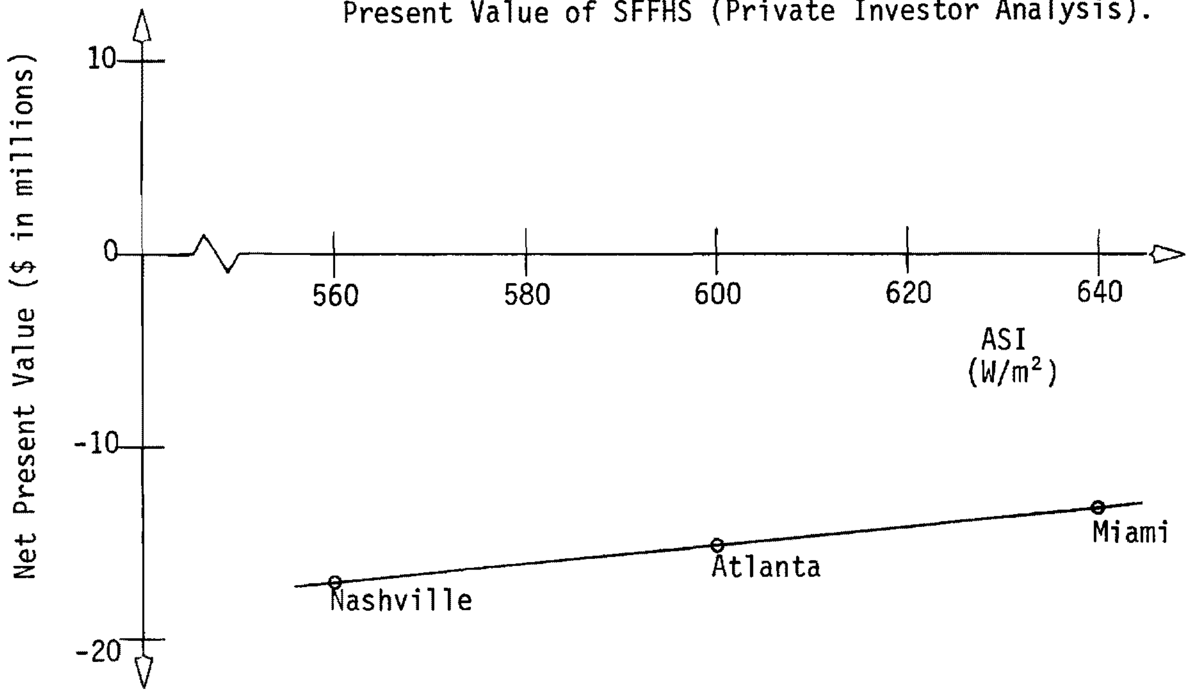


Figure 12. Influence of Annual Hours of Sunshine on Net Present Value of SFFHS (Private Investor Analysis).

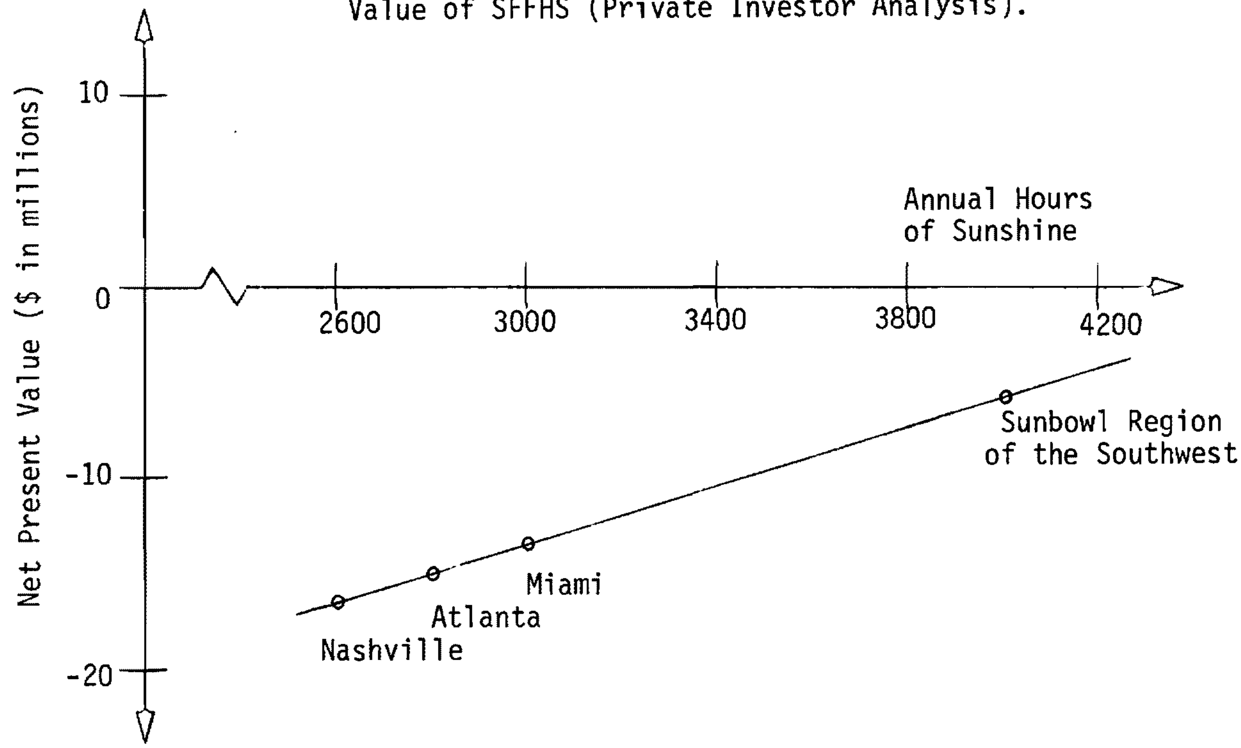


Figure 13. Influence of Life of Facility on Net Present Value of SFFHS (Private Investor Analysis)

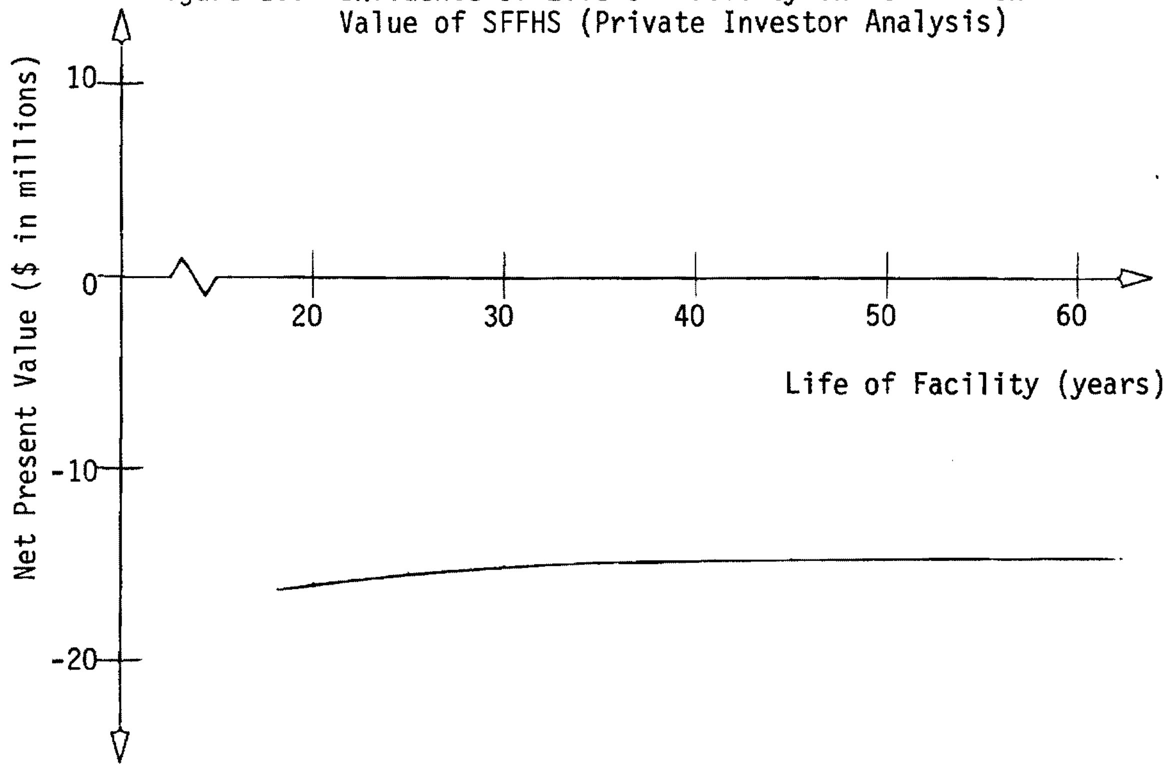
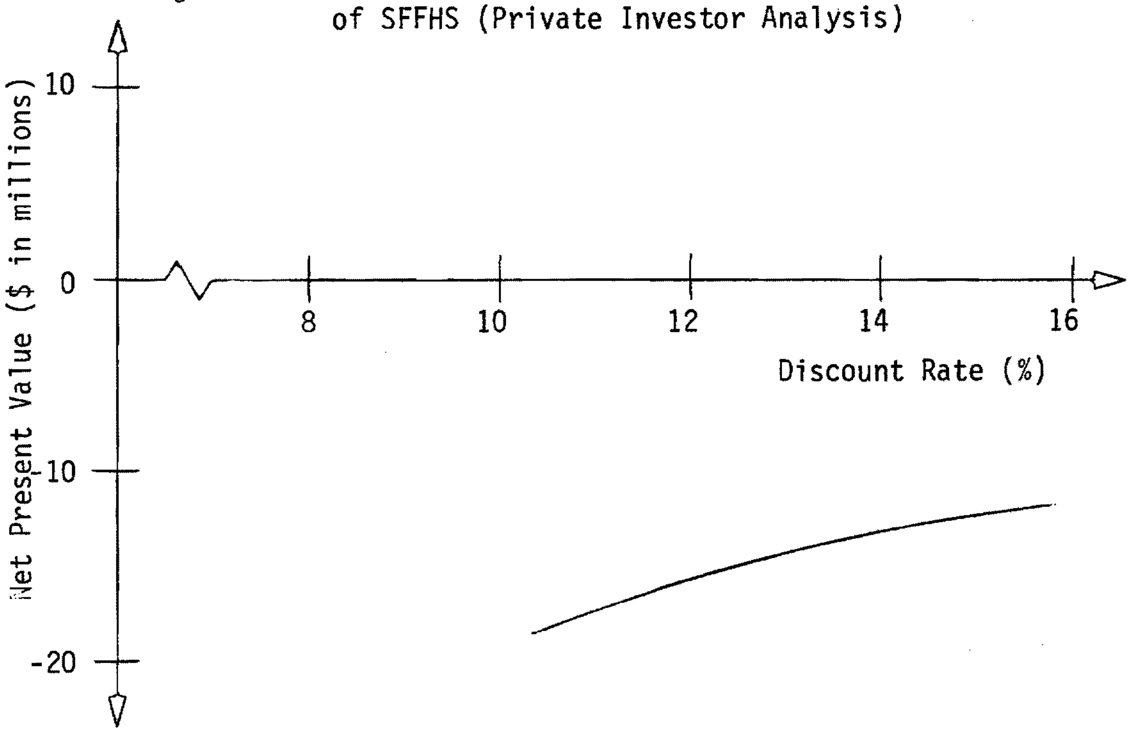


Figure 14. Influence of Discount Rate on Net Present Value of SFFHS (Private Investor Analysis)



some larger interest rate, the NPV will become positive because as the interest rate approaches infinity, the NPV approaches zero.

Several locations have been arbitrarily chosen as representative of the southeastern United States for a parametric study. For each location three scenarios were analyzed and the results are tabulated in Table 10. Columns five and six are based on a static price of coal, columns seven and eight on the price of coal annually increasing by one percent above the inflation rate and columns nine and ten on the price of coal annually increasing by 2.5 percent above the inflation rate. In all locations in the first two scenarios the analysis indicates a SFFHS would not be economically feasible to generate electricity. However, in scenario three it would be economically advantageous to retrofit an existing coal facility with solar hardware in the Miami area. This is primarily a result of the high cost of coal in this area coupled with the high solar insolation and annual hours of sunshine.

Conclusions

The analyses suggest that for the present price of fuel and present facility installation cost, it is not economically feasible to generate electricity using a solar fossil-fueled hybrid system in the southeastern United States. However, the values for the solar insolation were understated and conventional fuel prices will probably increase. The solar insolation values used represented the direct radiation on a horizontal surface while the postulated system utilizes tracking mirrors that are substantially more efficient. In addition, based on the sensitivity analyses, the fuel price need only increase to \$1.32/MBTU (\$1.69/MBTU in the private investor analysis) in the national welfare analysis for the

Table 10. Site Analysis for Private Investor

					Static Price		1% Annual Fuel Price Increase		2.5% Annual Fuel Price Increase	
	ASI W/m^2	Sun-shine Hours	Coal Price* $/MBTU	Eff of Coal Plants	Net Present Value ($)	Net Benefits $/Kwh	Net Present Value ($)	Net Benefits $/Kwh	Net Present Value ($)	Net Benefits $/Kwh
Miami, FL	641	3000	1.09	.318	-8,127,163	-.0035	-2,404,394	-.0010	1,676,983	.0007
Atlanta, GA	598	2800	.97	.335	-15,790,929	-.0073	-11,278,914	-.0052	-8,061,025	-.0037
Raleigh, NC	629	2600	1.07	.358	-15,287,350	-.0076	-10,962,613	-.0054	-7,878,288	-.0039
Charleston, SC	613	2800	1.08	.345	-13,355,310	-.0061	-8,477,237	-.0039	-4,998,282	-.0023
Nashville, TN	561	2800	.93	.324	-17,844,692	-.0082	-13,371,870	-.0062	-10,181,933	-.0047

*December 1975 fuel prices

installation to pay for itself. Therefore, it is likely that in the future a SFFHS will become desirable.

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IV. WASTE-FOSSIL HYBRID SYSTEM

The problem of what to do with solid waste has long plagued our nation. Generally thought of as a nuisance, solid waste is now being investigated as a fuel and energy resource. Individuals who are optimistic about the energy potential of solid waste hope that the material and fuel benefits will outweigh the high capital and operating costs of processing waste into recoverable forms. At present, a variety of systems are being considered for Waste Energy Recovery Systems. Those that are most technically and economically feasible are listed below:

1) Shred Waste → Recover Materials → Burn Solid Waste Derived Fuel (SWDF) with Fuel in Power Plant
2) Shred Waste → Recover Materials → Pyrolyze SWDF Portion to a Fuel (Liquid or Gas)
3) Shred Waste (optional)→Recover Materials → Burn SWDF in a Water-Walled Incinerator to Produce Marketable Steam.

The system investigated most thoroughly in the research effort was that producing SWDF for combustion in a fossil-fuel power plant. There are several reasons for this selection:

1) Many localities (e.g., St. Louis, Chicago, Milwaukee, and Ames, Iowa) have planned and are constructing this type of system.
2) This system, a Waste-Fossil Fuel Hybrid System (WFFHS), involves the direct use of SWDF in a power plant, and is thus directly relevant to the research program.
3) At the present time, the WFFHS appears to be the most economically attractive system.

Postulated System

Processing Plant. Any proposed WFFHS involves three basic components: (1) processing plant, (2) transportation and (3) power plant.

The processing plant is the most capital intensive part of the system. Waste processing can involve several types of operations including size reduction, air classification, material recovery, in-plant waste conveyance, and storage. Processing plants can vary extensively in design depending on the type of waste input, desired quality of recovered materials, and the desired quality of SWDF. One possible design is shown in Figure 15.

The process of shredding utilizes large hammermills which literally pound the waste through small openings in a grate to reduce the size of the incoming material. The primary shredder shown in Figure 15 reduces the waste to a six inch mean particle diameter. The secondary shredder reduces the waste to less than one inch in diameter. A magnetic separator is located in between the shredding operations. The main component of the separator is a strongly magnetic belt or drum. As the waste passes near the separator, particles containing ferrous metal cling to the magnetic surface. The recovered ferrous metal product is attractive to several markets, including the detinning plant shown in Figure 15 which further refines the ferrous product and sells it to recycled steel and tin markets.

The non-ferrous material enters an air classifier which separates the light fraction (mostly combustible) from the heavy fraction (mostly non-combustible). Air-classification is not a complex operation, but it is a relatively new and still developing means of separating waste. After classification, the lighter air-classified products are transported to the power plant for combustion; the heavy, non-ferrous fraction can be processed further. Aluminum and other non-ferrous metals can be separated using techniques such as an aluminum magnet. Glass separation operations (e.g., froth floation) also can be in-

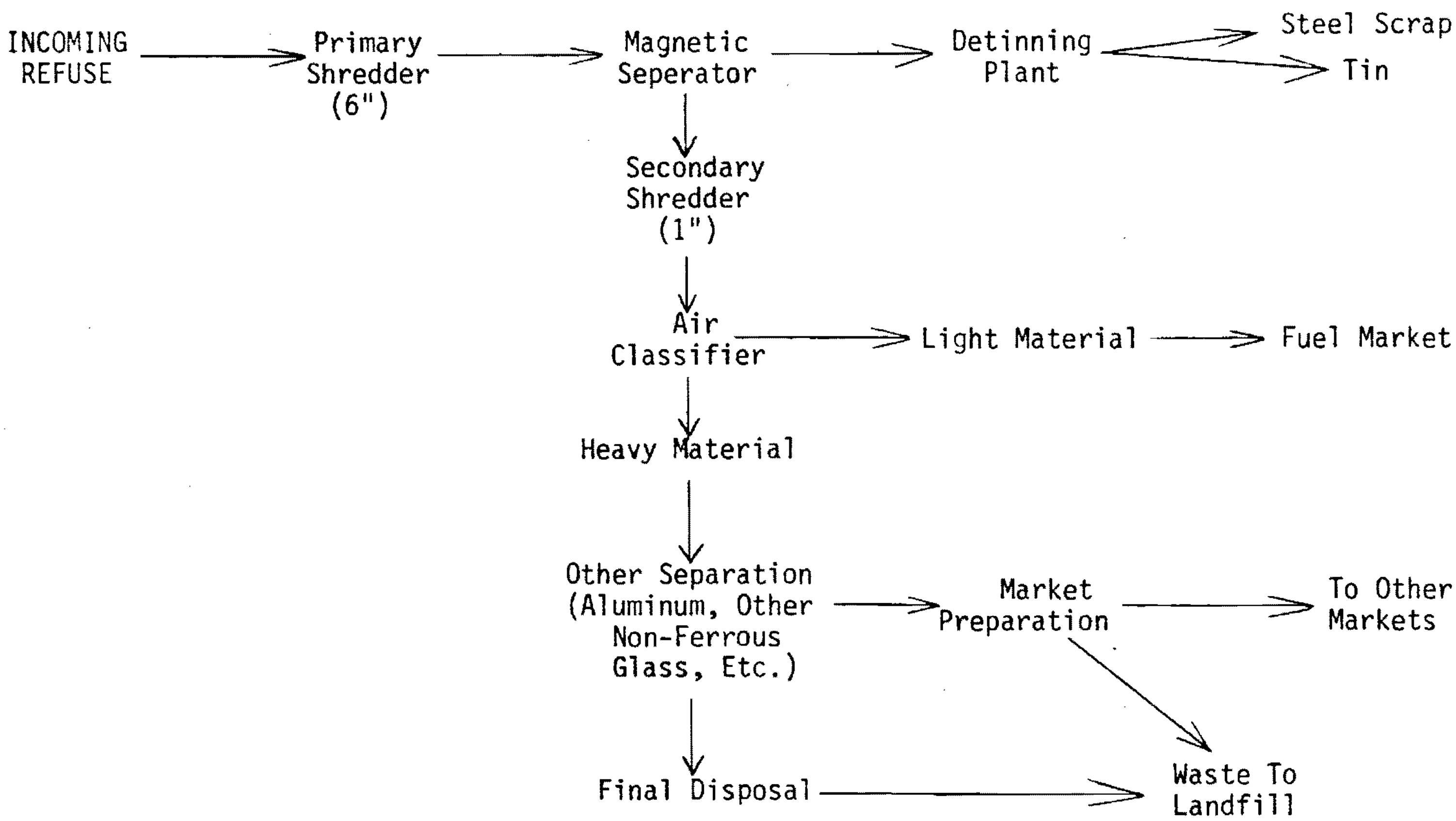


Figure 15. Possible Design of Municipal Waste Processing Plant

SOURCE: Conversation with David Klumb, Manager of Solid Waste Utilization System. Union Electric Company, St.Louis, Missouri, October 31, 1965.

cluded in the processing scheme. As these technologies are currently unproven, aluminum and glass recovery are not considered in the initial economic analysis. After all processing, a residue will be left which is probably not marketable. Most proposed WFFHS plan to landfill this residue.

Power Plant. The light weight air-classified portion of the processed waste is to be burned in conjunction with a conventional fossil fuel in an electrical power plant boiler. Combustion of solid waste derived fuel (SWDF) will produce substantial amounts of fly ash and bottom ash. Ash control equipment is required to treat these effluents. Because coal-burning power plants already require this equipment, use of SWDF is most attractive to these plants.

Modifications required in an existing power plant to enable SWDF combustion can include the following:

1) some form of temporary storage (i.e., surge bin)
2) conveyance and feed devices
3) a high-powered blower
4) pneumatic piping from the blower to the furnace
5) input jets located in the walls of the furnace
6) additional particulate control equipment.

Several types of coal-burning boilers are used in modern power plants. Those considered feasible for SWDF combustion include front-fired, opposed fired, tangentially fired and cyclone furnaces. The most popular furnace for this sytem is tangentially fired. This type is to be used in Waste-Fossil Fuel Hybrid Systems in St. Louis and Chicago. Milwaukee proposes to use a variation of a front-fired furnace. Memphis is investigating the use of SWDF in the nearby Allen steam plant's cyclone boiler. Table 11 lists characteristics of firing facilities in several proposed sites for WFFHS.

Table 11. Characteristics of Firing Facilities

Location	Name of Plant	Distance From City (mi)	Total Capacity (megawatts)	Type of Firing
St. Louis	Merimac	10	923	Tangential & Front
	Labadie	30	1175.5	Tangential
Milwaukee	South Oak Creek	6	1192.6	Front Wall Vertical
	North Oak Creek	6	500	Downward
Chicago	Crawford	20	597.5	Tangential
Memphis	Allen	5	990	Cyclone
Knoxville	Bull Run	15	950	Tangential
	Kingston	20	1700	Tangential
	Sevier	60	823.2	Tangential

SOURCE: Tunnah, Barry G.; Hakki, Adel; and Leonard, Roger G.; Where the Boilers Are, National Technical Information Service Document No. PB 239 392, 1974.

As a supplemental fuel, processed urban waste can provide up to 20% of the heating requirements of a firing facility (31). The heating value of SWDF is about 5000 to 6000 BTU per pound. The fuel requirements of a 1000 MW_e power plant can be supplied by about 2.62 million tons of coal per year. If 10% of this requirement is met by SWDF, 572,000 tons of processed waste would be needed. Since during the processing operation about 30% of the weight of municipal waste is removed before SWDF is produced, an input of 817,000 tons of waste per year is needed. This requirement can be met by a city having a population of 1,493,000.

Transportation. Transportation is required between all components of the solid waste system. The current waste collection system can be used to collect and transport the waste to the transfer station or processing plant. Conveying the packed waste to the processing plant from the transfer station (if used) will be performed by either large packer trucks or packer rail cars. The final major transportation requirement—from processing plant to firing facility—can be performed by a variety of modes. Trucks, barges, rail, or pneumatic pipeline could all be used; the means selected depends on the location of and distance between the two sites.

Statement of Problem

The purpose of this task of the study was to evaluate the conditions for economic feasibility of Waste Fossil Fuel Hybrid Systems. The evaluation is approached from two perspectives; national (societal), and private investor. The methodology used is Cost Benefit Analysis; the procedures used in this type of analysis are discussed in Chapter II.

In order to determine economic feasibility, the Waste Fossil Fuel Hybrid System is treated as a possible investment project and compared with the status quo (traditional waste treatment methods and conventional coal-fired power plants). The analysis assumes that the status quo system was in place and that the proposed WFFHS would be adapted to the current system. The economic feasibility of a WFFHS depends upon the relationship between the additional capital and operating costs required for utilizing SWDF and the additional benefits of using SWDF, which include revenues for resources recovered and the value of the replaced coal.

Technical Parameters

The design of a WFFHS can vary extensively and thus produce wide ranges in the costs of the system. The processing plant, the most costly component of the WFFHS, can recover a variety of resources from waste; those resources selected require a large capital investment for recovery. The location of the processing plant directly affects the transportation requirements of the system. If the processing plant is located near the firing facilities, pneumatic pipelines may be able to input SWDF directly in the boiler, thus overcoming the need for waste handling equipment at the power plant. If the distance between the processing plant and firing facility is great, capital investments in rail cars and extensive waste handling facilities at the firing facility will be required. The construction of transfer stations will result in additional capital and operating costs.

Important parameters that impact the cost of a WFFHS system are shown in Table 12. Ranges are shown where applicable. The important cost variables are shown in Table 13. Values for these variables are derived from an extensive literature survey, a number of interviews, and attendance at several conferences dealing with WFFHS.

Table 12.

List of Cost-Impacting Parameters

Parameter	Range of Values
A. Average collection distance (waste to transfer station or processing plant)	
B. Distance from transfer station to processing plant	
C. Distance from processing plant to firing facility	
D. Type of transportation system	Truck, Barge, Rail, Pipeline
E. Materials to be recovered during processing	Paper, Ferrous Metal, Glass, Non-Ferrous Metals
F. Type and capacity of boilers	Tangential, Front, Opposed, Cyclone
G. Operating cost of the power plant (current) (to compute Economic Dispatch Penalty)	
H. Difference in emissions (coal plant vs. hybrid plant)	
1) SO_2 (2.5% sulfur coal)	0.7 lbs SO_2/MBTU of fuel
2) Particulate	
I. Capacity of the system	
J. Heat content of SWDF	10-12 million BTU/ton
K. Percentage of recoverable materials in waste:	
1) Ferrous	5-10%
2) Glass	8-10%
3) Non-Ferrous	.9%
4) Paper	20-40%

Table 13.

List of Economic and Financial Parameters

Social Discount Rate
Private Interest Rate
Lifetime of Facility (period of depreciation)
Taxation Regulations
Method of Depreciation
Desired Rate of Return
Financial Structure of WFFHS
City owns processing plant, Utility owns transportation and power plant
City owns processing plant and transportation, Utility owns power plant
City owns entire WFFHS
Utility owns entire WFFHS
Etc.
Contractural Agreements (markets for SWDF and recovered materials)

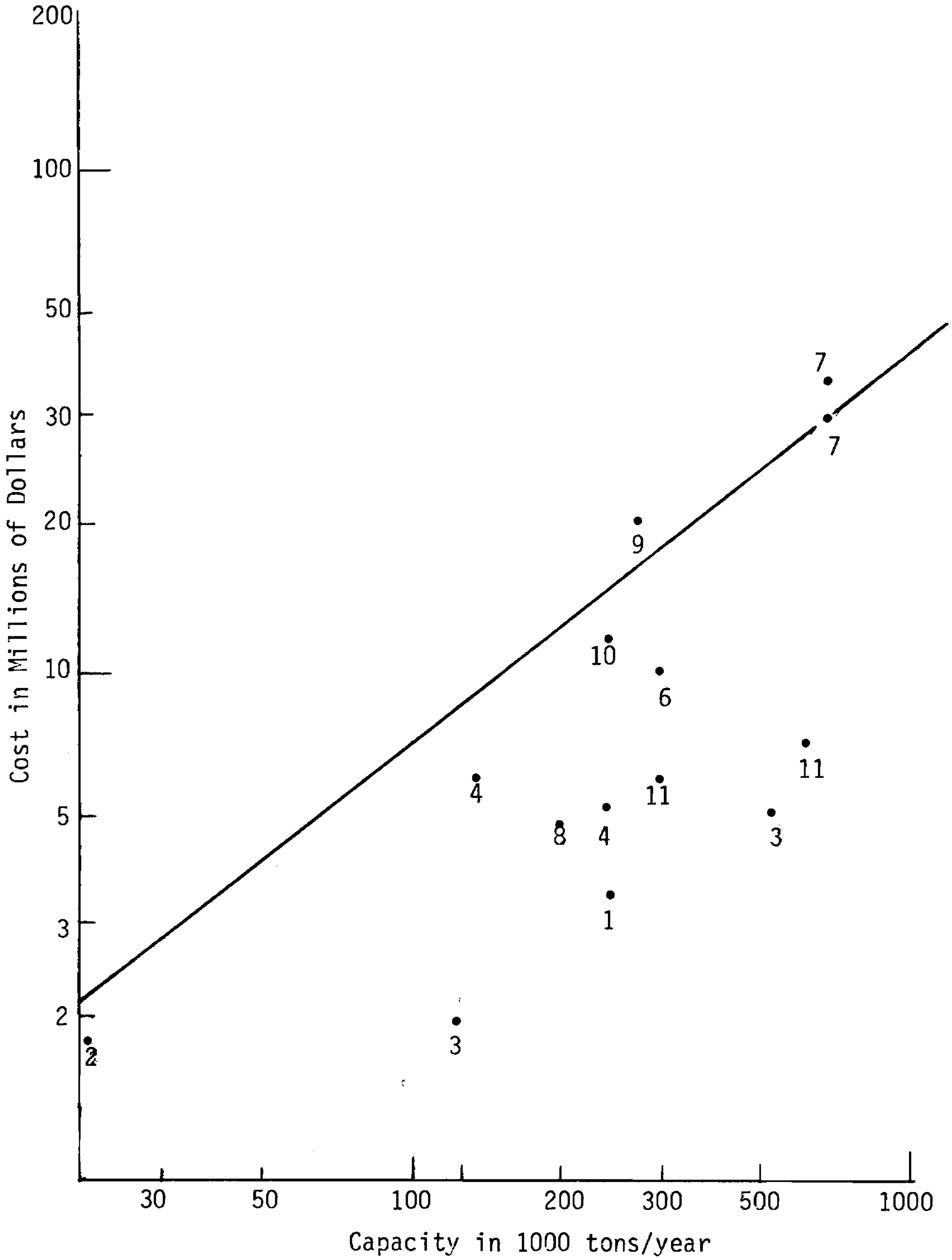
An initial analysis is performed to evaluate the economic feasibility of a typical WFFHS. The proposed system handles 1000 tons of waste per day. Waste is processed in a plant that recovers only ferrous metal. Solid waste derived fuel (SWDF) is produced and pneumatically transported to a nearby tangentially fired coal power plant. No transfer station is used. The processing plant is within 5 miles of the center of the city; the costs of collecting the waste and transporting it to the processing plant are not expected to exceed current collection costs. The former waste disposal system landfilled the refuse collected. These facilities are not used now that the WFFHS is operating; an auxilary landfill for the residue of the processing operation is located near the power plant. The processing plant operates 16 hours a day for 5 days of the week. The annual amount of waste treated is about 260,000 tons; 70% of the waste, about 182,000 tons, is burned in the power plant. The heat content of the SWDF is approximately 11 million BTU/ton. It is assumed that the utility (a private investor) owns the entire WFFHS.

Determination of Cost Estimates. The most difficult parameters to assign values are the capital and operating costs. This difficulty occurs primarily because a full-scale WFFHS has yet to be implemented. The St. Louis prototype system proves that such a system can operate; however, the economics of this particular system make it quite unattractive. The St. Louis system suffered a number of setbacks which were caused by technical problems that now have been recognized and, in most cases, can be avoided in future plants. The main problem with the system was not that the capital costs were excessive but that the amount of waste processed and burned was far below the system's capacity. This low level of capacity utilization resulted in a high cost per ton of waste treated and, consequently, a poor economic performance.

A number of cost estimates for processing plants are shown in Figure 16; the sources for these estimates are shown in Table 14. These estimates do represent a wide range and it is difficult to accurately assign values for the cost of a processing plant. The line is the basis for the estimate used in the initial analysis. Table 15 shows different estimates of operating and maintenance costs for processing plants at different sizes. The Louisville estimate ($5.82/ton) and the Bechtel estimate ($8.64/ton) are both considered in the analysis. The Louisville estimate is used in the initial analysis.

Figure 17 shows estimates for the required power plant modification to burn SWDF. The line is the basis for the costs used in the initial analysis. It is assumed that annual operating and maintenance costs are 7% of capital costs.

Another cost that could be incurred by a WFFHS is an economic dispatch penalty. This cost results because the SWDF is used in a power plant that may be several years old. If modifications are made and contracts are signed to burn waste, the plant will have to operate for another 20 years to meet the needs of the WFFHS. This may be contrary to utility plans for replacing part of the load of the WFFHS plant with power from a new plant that would be cheaper to operate. The economic dispatch penalty is the difference in operating costs between the WFFHS plant and the plant that is to replace it. Since the old plant would presumably still be used for intermediate load or peak load demands, the penalty is only incurred during periods when the plant was not to be used. By multiplying the $/KWH economic dispatch penalty by the total electrical output under penalty conditions, an annual economic dispatch cost can be derived. This cost should be estimated for each



Formula for the line is: Cost = \$1353.3 (capacity)$^{.75}$

Figure 16. Cost Estimates of Processing Plant Processing Costs

Table 14.

COST ESTIMATES OF MUNICIPAL WASTE PROCESSING PLANTS

	Source of Estimate	Capacity	Processing Plant	Power Plant Modification
1.	"St. Louis Power Plant to Burn City Refuse," Civil Engineering	980 tons/day 254,800 tons/yr	\$3,427,000	\$1,205,000
2.	Refuse as a Supplementary Fuel for Power Plants, Actual Costs of St. Louis Plant	9,393 tons/5mo 22,543 tons/yr	\$1,741,237	\$ 956,816
3.	Energy Recovery from Waste, EPA (SW-36dii)	30 tons/hr 480 tons/day 124,800 tons/yr	\$1,680,000-2,160,000	\$1,440,000-1,680,000
		125 tons/yr 2,000 tons/day 520,000 tons/yr	\$4,000,000-6,000,000	\$4,000,000-5,000,000
4.	Recovering Resources from Solid Waste Using Wet-Processing, EPA's Franklin, Ohio, Project: EPA (SW-47d)	500 tons/day 130,000 tons/yr	\$5,900,000	
5.	"Economical Utilization of Solid Waste as a Fuel for Energy Conversion," Cost Effectiveness in Pollution Control	95,000 tons/yr	\$1,360,000	\$ 900,000

Table 14. (continued)

COST ESTIMATES OF MUNICIPAL WASTE PROCESSING PLANTS

Source of Estimate	Capacity	Processing Plant	Power Plant Modification
6. Fuels from Municipal Refuse for Utilities: Technology Assessment, Bechtel, 1974	1000 tons/day 313,000 tons/yr	$11,000,000	$4,000,000
7. Resource Recovery Seminar, Knoxville, Tennessee, October 17, 1975 (TVA System)	2000 tons/day 728,000 tons/yr	$35,000,000- 38,000,000	$25,550,000
8. Interview with Rex Taylor, at Ames, Iowa, WFFHS, October 30, 1975	50 tons/hr 200,000 tons/yr	$ 4,500,000	
9. Preliminary estimate of WFFHS in DeKalb County, Georgia, November 1975	1100 tons/day 286,000 tons/yr	$19,623,000	$4,610,000
10. DeLeuw, Cather and Co., Final Report on Solid Waste Mgt. and Disposal System for the City of Milwaukee, Wis., April 1975	1600 tons/day 250,000 tons/yr	$11,660,000	
11. Horner and Shifrin, Inc., Appraisal of Solid Waste as Supplementary Fuel in Power Plant Boilers, Louisville, KY Area, Jan. 1975	1000 tons/day 2000 tons/day 800 tons/day	$6,011,000 $8,083,000 $5,966,000	$ 593,300 $1,038,600

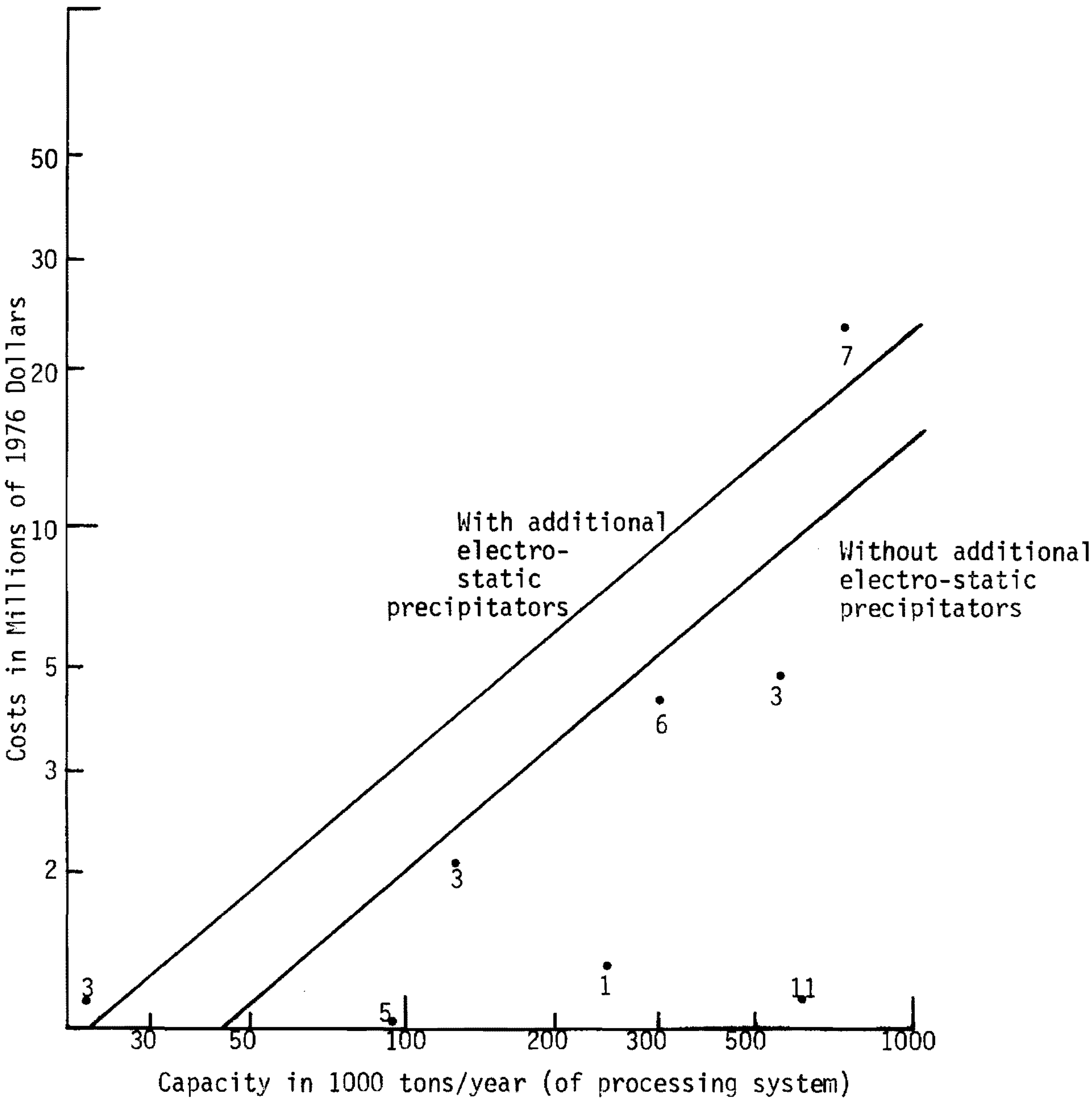
Table 15.

Estimates of Operating and Maintenance Costs for WFFHS

Source	Year	Estimate	Updated Estimate[1]
(see Table 14)			(1977 dollars)
1	1974	2.18	2.60
2	1974	5.63	6.71
3	1974	5.00	5.96
4[2]	1974	8.77	10.44
5	1974	2.57	3.06
6	1974	7.25	8.64
7	1977	5.50	5.50
11	1977	5.82	5.82

[1]Assume 6% annual increase

[2]Wet Processing



Formula for the line is Cost = \$115.36 (processing capacity in tons/year)$^{.85}$ (without Electro-Static Precipitators)

Figure 17. Cost Estimates of Power Plant Modifications

future year that the penalty is incurred. The costs should then be discounted over all years at appropriate rates.

In the proposed system, the power plant to be modified is assumed to be relatively new. Operation of the proposed system is therefore not expected to result in an economic dispatch penalty over its 20 year life.

Capital costs for transportation facilities are based on the TVA estimate, which is equivalent to $1.90 per ton of annual capacity, or $494,000. Transportation operating costs of $.70 per ton, estimated from information received from TVA, are assumed.

Determination of Benefits. The operating costs of the current landfill will no longer be paid once the system is implemented; thus, this cost can be viewed as a net benefit. Table 16 shows the range of costs for landfilling in the Southeast. DeKalb County, Georgia, has quite high costs due to shortages of landfill space which may soon be encountered in other cities. A relatively high value of $4/ton is used in the initial analysis.

The proposed system will recover ferrous metal as a marketable product. This material composes about 10% of municipal refuse; however, not all of it can be recovered. An 8% estimate was used. The price paid for ferrous metal varies significantly; from $2/ton in Connecticut (8) to $45/ton (29) in the TVA region. The TVA estimate was based on actual bids by potential buyers. The project team used a substantially lower price of $20/ton.

In later analyses, the potential for aluminum and glass recovery will be considered. Estimates for market prices of recovered aluminum include $300/ton (4) and $450/ton (29). Once again, the TVA figure, $450/ton, is based on an actual bid. The more conservative $300/ton estimate is used in subsequent analyses. The percentage of recoverable aluminum in waste is estimated to be .6% (17).

Table 16.

Costs of Landfilling in Southeastern Cities*

Birmingham, Alabama	\$1.40/ton
Mobile, Alabama	\$1.50/ton
Jacksonville, Florida	\$2.50/ton
Orlando, Florida	\$1.60/ton
Atlanta, Georgia	\$2.00/ton
DeKalb County, Georgia	\$6.90/ton
Macon, Georgia	\$3.00/ton
Savannah, Georgia	\$3.50/ton
Jackson, Mississippi	\$1.60/ton
Charlotte, North Carolina	~ \$2.00/ton
Greensboro, North Carolina	\$3.20/ton
Raleigh, North Carolina	\$2.37/ton
Memphis, Tennessee	> \$1.80/ton

*These costs are based on telephone interviews with officials of the municipalities listed. In most cases, the cost given does not reflect the true cost of landfilling due to peculiarities in the accounting procedures. For example, in some cities, revenue sharing funds are allocated to waste disposal, and landfill charges are artificially low. In other locations, all disposal costs are lumped as components of landfill costs; in such cases, landfill charges are artificially high.

A price of $15/ton for recovered glass has been estimated by both the Bechtel and the TVA study. Bechtel assumes 9.8% of the refuse is recoverable as glass. The estimate used in our later analyses is a lower 8.0% figure.

Estimates of the environmental benefits of burning waste versus burning coal in a power plant have been subject to disagreement. Waste produces substantially more particulates upon combustion than coal; however, several sources indicated that electro-static precipitators on coal-burning power plants would be able to control particulate emissions (28). TVA disagrees and says that this type of emission might pose a problem (29). An initial test of emissions at the St. Louis prototype power plant was declared to be invalid. However, subsequent tests have estimated that a 1 to 2% increase in particulate emissions would result. Georgia Power Company (GPC) used the upper 2% figure to estimate a $20-24 million dollar requirement for improving the electro-static precipitators (ESP) on two 880 MW_e units proposed as components of a WFFHS in conjuction with DeKalb County, Georgia. DeKalb County had proposed to supplement 10% of the energy value of the fuel in these plants with SWDF. The amount of waste combusted in one unit, if the plant operated with an 80% load factor, would be 574,000 tons per year. In the proposed system, only 186,000 tons per year (or 32% of the waste used in one unit of the GPC/DeKalb County WFFHS) would be combusted. Assuming that cost of ESP modification is proportional to the amount of waste burned, this modification would cost $3.24-$3.89 million. A mean of $3.56 million is used in the analysis.

Sulfur dioxide emissions present the opposite case because waste contains substantially less sulfur than coal, whose sulfur content ranges from .4% to 4% and higher. No test results on the differences in SO_2

emissions between hybrid waste-coal power plants and coal-power plants were available. The project team made the assumption that the differences in SO_2 emissions were proportional to the differences in the sulfur content of the fuel. Table 17 summarizes the analysis. The initial run of the model assumes that coal with a 2% sulfur content is used in the power plant. The emission differences are estimated at 2.55 lbs SO_2/MBTU burned. With an annual waste combustion of 186,000 tons, the annual air pollution benefits would be about $17,300, a relatively insignificant portion of the total benefits of the system.

The benefit that has the most favorable impact on WFFHS economics is the value of the processed waste fuel. This value is assumed to depend directly on the cost of coal. The chapter on Solar-Fossil Fuel Hybrid Systems discussed the BTU cost of southeastern electricity fuels in some detail. A $1.04/MBTU estimate is used in the initial analysis.

Rates of Cost Increase. In order to realistically represent the operation of the WFFHS, all costs are inflated at an annual rate of increase. In the initial analysis, coal is increased at 6% annually landfill operating costs at 5%, ferrous metal revenues at 5%, and operating and maintenance costs of the facility at 5%.

Economic Parameters

To perform an economic analysis on the postulated system, values are needed for economic and financial parameters shown in Table 13. The economic analysis used viewed the WFFHS from a National Welfare context. The relevant parameters for this type of analysis were the social discount rate and lifetime of the facility. The discount rate was discussed in earlier chapters; it was assigned an annual value of 7%. The lifetime of the WFFHS was assumed to be 20 years.

Table 17.

Analysis of Emission Cost Differences: Coal vs Waste

	Particulate Matter		SO_2	
	High[1]	Low[2]	High	Low
Estimated Emission Differences:	(Tons of Emissions/MBTU Burned) x (10^{-3})			
1% Sulfur Coal vs Waste	3.18	2.15	.67	0
2% Sulfur Coal vs Waste	3.18	2.15	1.46	.79
3% Sulfur Coal vs Waste	3.18	2.15	2.23	1.56
Average Sulfur Coal for Southeast (2.3%) vs Waste	3.18	2.15	1.69	1/02
Cost per Ton of Emission[3] (in $/ton)	25		7.3	
Estimated Environmental Benefits(+) and Costs (-) of Waste Combustion in Southeastern Power Plants ($/MBTU)	-.19[4]	-.16[4]	$.012	$.007

[1] High Waste Benefits Result when High Coal Emissions are Compared to Low Waste Emissions

[2] Low Waste Benefits Result when Low Coal Emissions are Compared to High Waste Emissions

[3] Justus, Economic Costs of Air Pollution, see Working Paper IV

[4] This figure represents the Georgia Power Company estimate discounted at 7% for 20 years, based on a .8 plant factor for two 880 MW_e units operating at 35% efficiency.

Analyses and Results

This section first summarizes the results from a national and private investor's perspective, then presents a sensitivity analysis to interpret the results of the Cost Benefit Analysis (CBA).

National Welfare. Using the values discussed in the previous section, the cost-benefit model was run to determine the net benefit (or cost) of the proposed Waste-Fossil Hybrid System. A summary of the values for the model parameters and disclosure of the results of the model's analysis is shown in Table 18. Under the assumptions made, the WFFHS discussed would have a net benefit of $1.50 per ton of waste processed in constructed in 1977. This represents a significant benefit to society.

Private Viewpoint. When considering the WFFHS from a private viewpoint, different results from the economic analysis occur. The methodology used in the private investor analysis was discussed in the previous chapter. Table 19 displays the economic performance of the WFFHS under private investor criteria. The Net Present Value of the proposed system is -5.52 million dollars; this would add $2.34 to the cost of every ton of waste collected. This analysis has revealed a dilemma, in which a private investor could not afford to construct a Waste-Fossil Fuel Hybrid System from which society would benefit. This discrepancy is evaluated using two approaches: first, a sensitivity analysis in which changes in parameter values are evaluated to determine their effect on the desirability of the system from both societal and private viewpoints; second, a brief analysis of alternative policies is used to disclose their effectiveness.

Sensitivity Analysis. This type of procedure can reveal to what extent uncertainties in parameter estimates will affect the results of the CBA.

Table 18. Results of Initial Analysis From Societal Viewpoint

	Increases	Value in Initial Year(1976) ($1000)	Present Worth ($1000)
CAPITAL COSTS			
Processing Plant	.05	$15,582	$16,361[1]
Firing Facility Modification[2]	.05	8,222	8,633
Transportation	.05	494	519
Subtotal			$25,513
OPERATING AND MAINTENANCE COSTS			
Processing Plant	.05	$ 1,513	$27,544[3]
Firing Facility Modification	.05	575	10,476
Economic Dispatch Penalty	.05	0	0
Transportation	.05	182	3,313
Subtotal			$41,333
BENEFITS			
Previous Landfill Costs	.05	$ 1,147	$20,871
Ferrous Metal Recovery	.05	416	7,572
Environmental (SO_2 reduction)	0	17	183
Fuel Value of Waste	.06	2,082	42,456
Subtotal			$71,082
NET PRESENT VALUE			$ 4,236
AMORTIZED BENEFITS IN $/TON PROCESSED			$1.54/ton

[1]Escalated at 5% over 1 year construction time

[2]Includes cost for Electro-Static Precipitator Modification

[3]Escalated for 2 years at annual % increase, then discounted over 20 year life.

Table 19

Derivation of Net Present Value for Private Investor Analysis

Year of Operation	Interest and Principal Payments[1]	Net Benefits Excluding Interest[2]	Discounted Net Cost Flow[3]
1	2168.60	1476.16	-618.25
2	2168.60	1532.25	-507.30
3	2168.60	1591.92	-410.48
4	2168.60	1655.38	-326.16
5	2168.60	1722.90	-252.91
6	2168.60	1794.70	-189.43
7	2168.60	1871.08	-134.58
8	2168.60	1952.31	- 87.36
9	2168.60	2038.70	- 46.85
10	2168.60	2130.57	- 12.25
11	2168.60	2228.27	17.15
12	2168.60	2332.16	41.98
13	2168.60	2442.62	62.80
14	2168.60	2560.09	80.10
15	2168.60	2684.98	94.34
16	2168.60	2817.76	105.89
17	2168.60	2958.94	115.11
18	2168.60	3109.03	122.29
19	2168.60	3268.58	127.71
20[4]	27681.60	3438.21	-2513.23
NET PRESENT VALUE			-5525.51 -$2.84/ton

[1] Interest Rate is 8.5%, all numbers are in thousands of dollars.

[2] Includes Taxes

[3] Discounted at 12%

[4] Year that principal is repaid

Table 20 displays the sensitivities of several variables used in the analysis. The sensitivities, based on the social welfare analysis, have relatively high values due to the close proximity of the Net Present Value (NPV) to the breakeven point (where NPV=0). In this case, a small change in a variable value results in a significant change in the NPV. For example, if the capital cost of the processing plant increases 1%, the NPV of the WFFHS decreases by 4.75% (to $4.03 million). Figures 18-25 display more fully the effects of changes in the most sensitive variable values on the NPV of the proposed system.

Figure 18 shows that a 26% increase in processing plant costs will reduce the societal NPV to the breakeven point (the value at which NPV=0). Considering the uncertainty of the processing plant cost estimate and the tendency for construction costs to be underestimated, due to labor problems, unanticipated material shortages, etc., it is possible that the cost could exceed this level of increase. In order for the private investor to achieve a 12% return on investment (ROI), the capital costs of the processing plant would have to be reduced by 52% (to 7.5 million 1976 dollars). This type of cost reduction is inconceivable.

Figure 19 shows the sensitivity of NPV to total capital costs. A 16% increase in costs would result in a breakeven situation in the social welfare analysis. As with processing plant costs, this increase is quite feasible. The private investor would have to reduce total capital costs 34%; once again, this level of decrease is highly unlikely.

Figures 20 and 21 present the sensitivity of NPV to operating and maintenance costs of the processing plant and of the entire system. As with Figures 18 and 19, unexpected cost increases of 20% and 10%, respectively, could reduce the societal Net Present Value to zero. The private investor

Table 20. Sensitivity Analysis

Variable Name	Sensitivity[1]
TOTAL CAPITAL COSTS	- 7.42
Capital Cost of Processing Plant	- 4.75
Capital Cost of Firing Facility Modification	- 2.51
Capital Cost of Transportation	- .15
TOTAL OPERATING & MAINTENANCE (O&M) COSTS	-12.02
O&M Costs of Processing Plant	- 8.01
O&M Costs of Firing Facility (additional)	- 3.05
O&M Costs of Transportation	- .96
TOTAL BENEFITS	20.44
Previous Landfill Costs	6.07
Ferrous Metal Recovery	2.20
Environmental	.05
Fuel Value of Waste	12.11
Social Discount Rate	- 4.56
Lifetime of Facility	3.94
Inflation Rate for Processing O&M Costs	- 3.42
Inflation Rate for Landfill Costs	2.59
Inflation Rate for Ferrous Metal Revenues	.94
Inflation Rate for Fuel Value	5.17

[1] Sensitivity $= \dfrac{\frac{\Delta NPV}{NPV}}{\frac{\Delta X}{X}}$

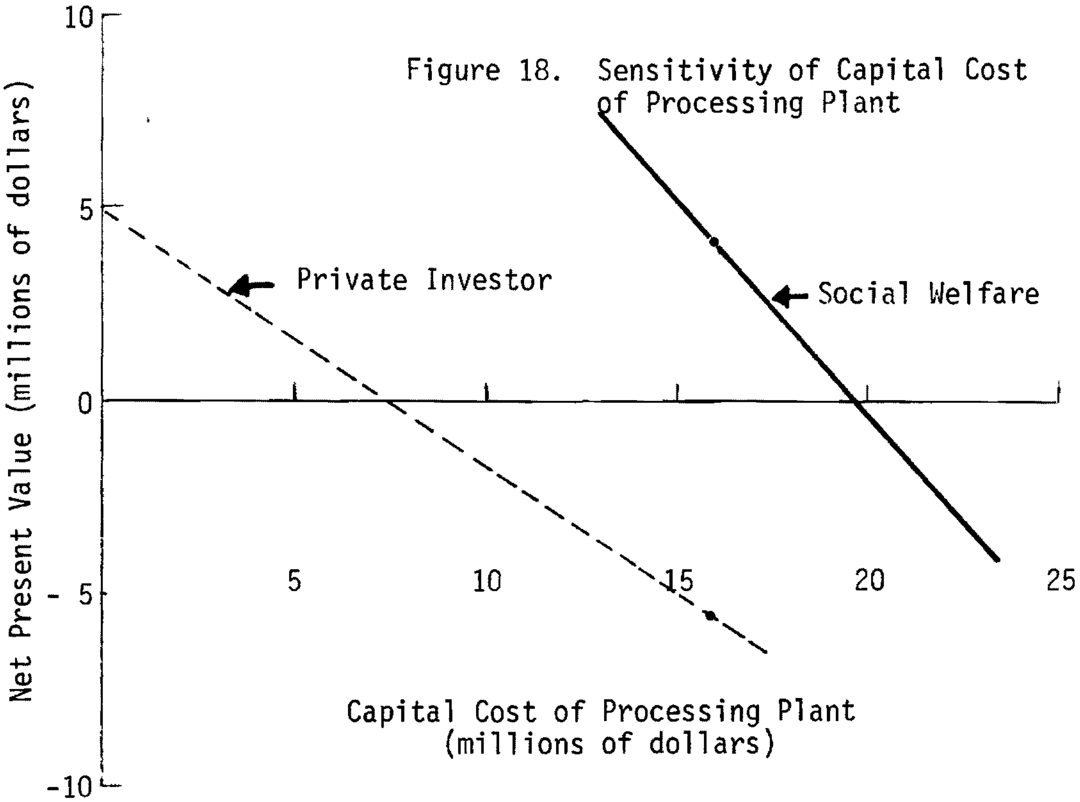


Figure 18. Sensitivity of Capital Cost of Processing Plant

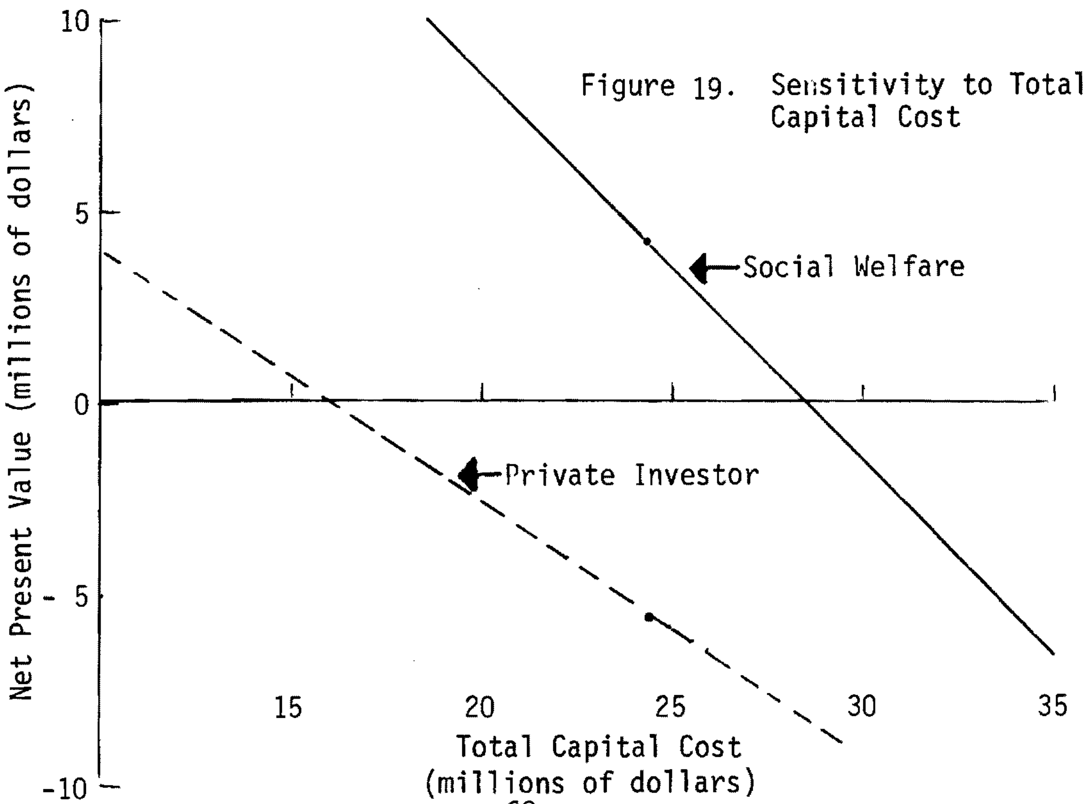


Figure 19. Sensitivity to Total Capital Cost

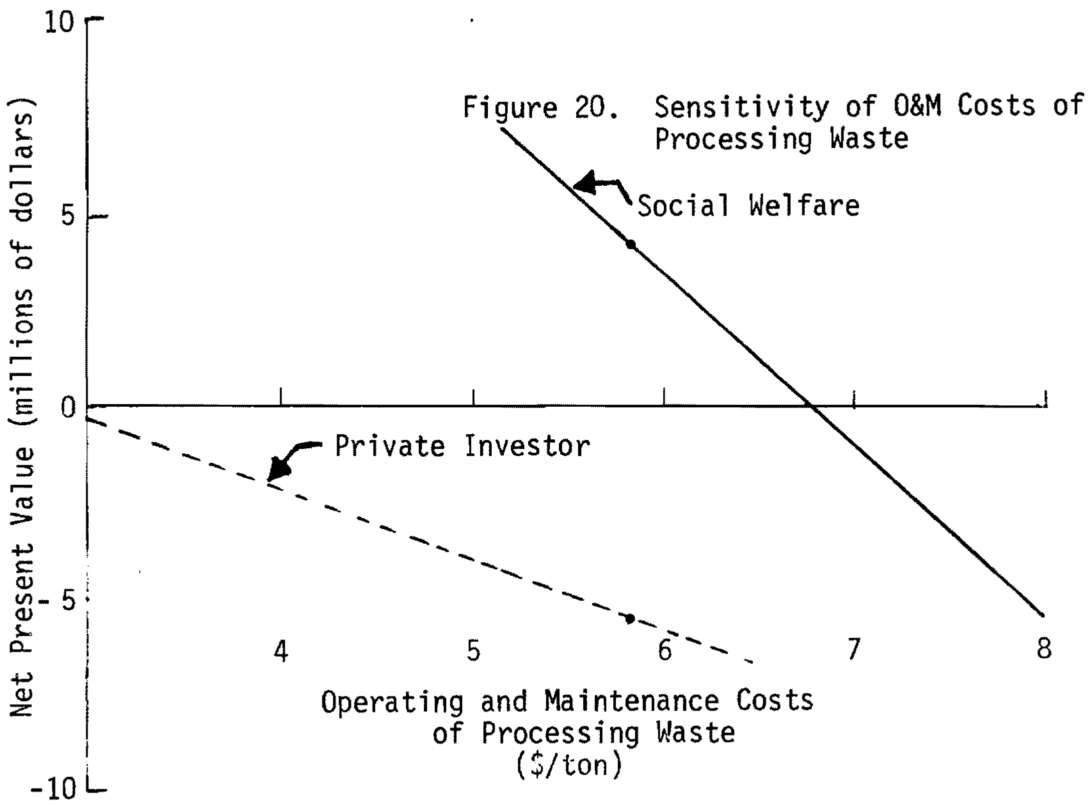


Figure 20. Sensitivity of O&M Costs of Processing Waste

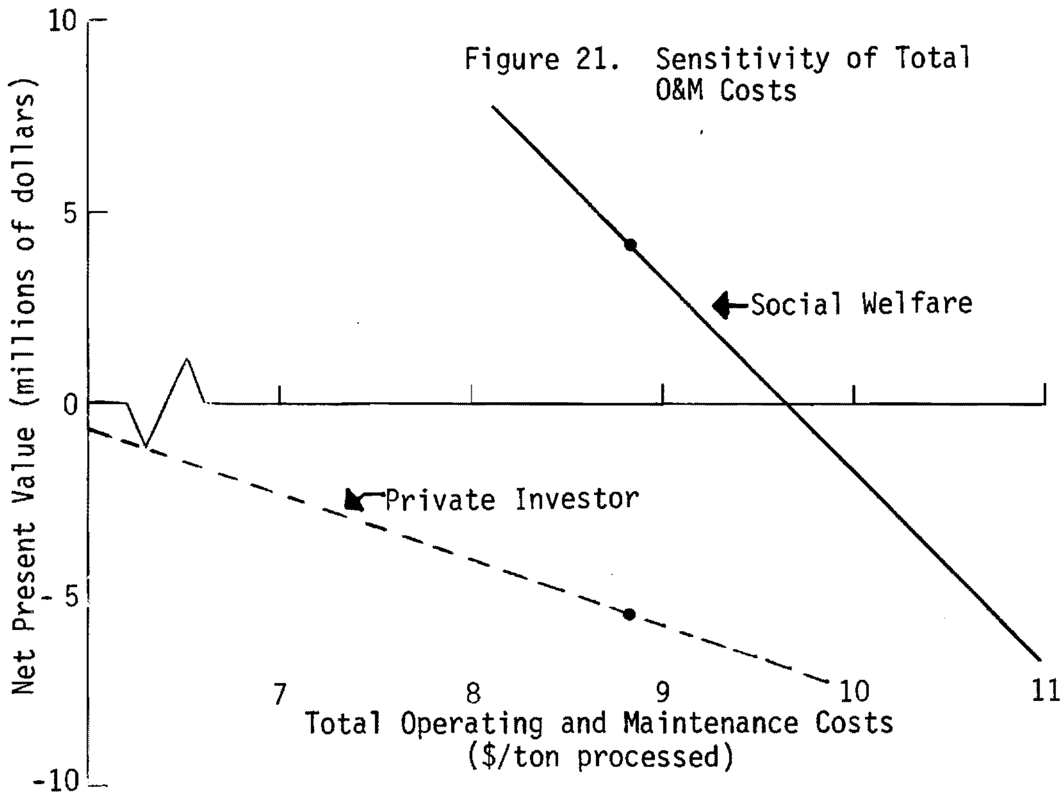


Figure 21. Sensitivity of Total O&M Costs

must decrease operating and maintenance costs by 52% and 36%, respectively, to receive his desired 12% return on investment.

Figure 22 shows the effect of varying landfill costs on the NPV of WFFHS. In the social welfare analysis, decrease of 33% (to $2.70/ton) in landfill costs would result in breakeven condition. In some localities in the Southeast, costs are this low; however, several locations have higher costs. The private investor would have to locate in an area with landfill costs of $8/ton. Although the costs of landfilling in Milwaukee are about $10/ton (8), costs in the Southeast have not yet reached the $8/ton magnitude.

Figure 23 displays the sensitivity of NPV to the cost of coal. In the societal case, a decrease of 10% (to $.96/MBTU) would reduce the NPV to zero. Utilities can still purchase coal at this price in some instances; however, they often have to settle for much higher prices (greater than $1.80/MBTU). The private investor would have to receive an equivalent cost of $1.40/MBTU for waste. Coal prices at this level are not unlikely.

Figures 24 and 25 examine the effect different rates of cost increase have on the attractiveness of WFFHS. Figure 24 shows that an increase in landfill costs of less than 2% annually would be required for the societal NPV to reach the breakeven point. Due to the increasing value of land, particularly near urban areas, such a low rate of increase is inconceivable. On the other hand, a 8.2% annual increase in landfill costs would yield the 12% ROI needed by the private investor. This moderate increase over the 5% value used in the initial analysis is quite possible.

Figure 25 shows that a small decrease in the inflation rate for coal (to 5%) would reduce the societal NPV to zero. It is much more likely, however, that the rate of increase of coal prices will be greater than 6%. For the private investor to earn his desired ROI, coal prices would have

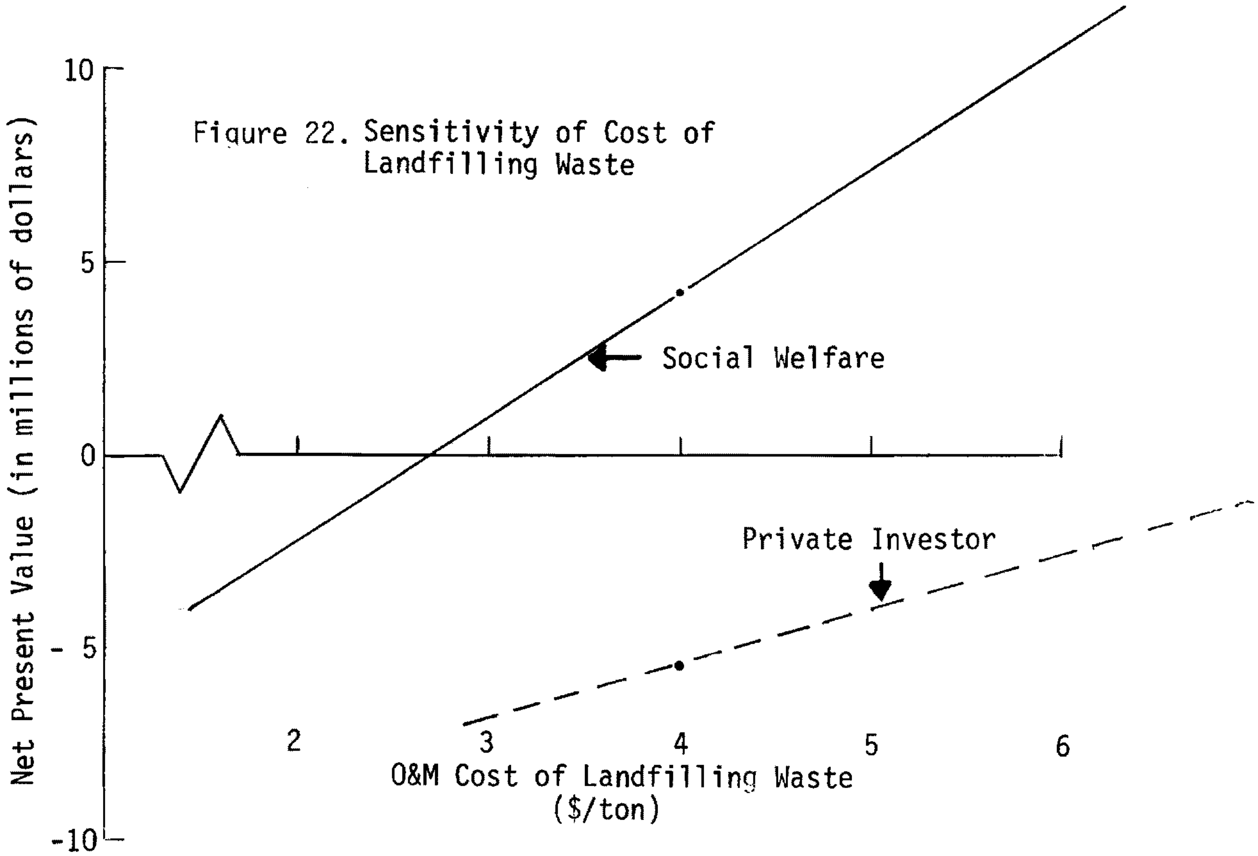


Figure 22. Sensitivity of Cost of Landfilling Waste

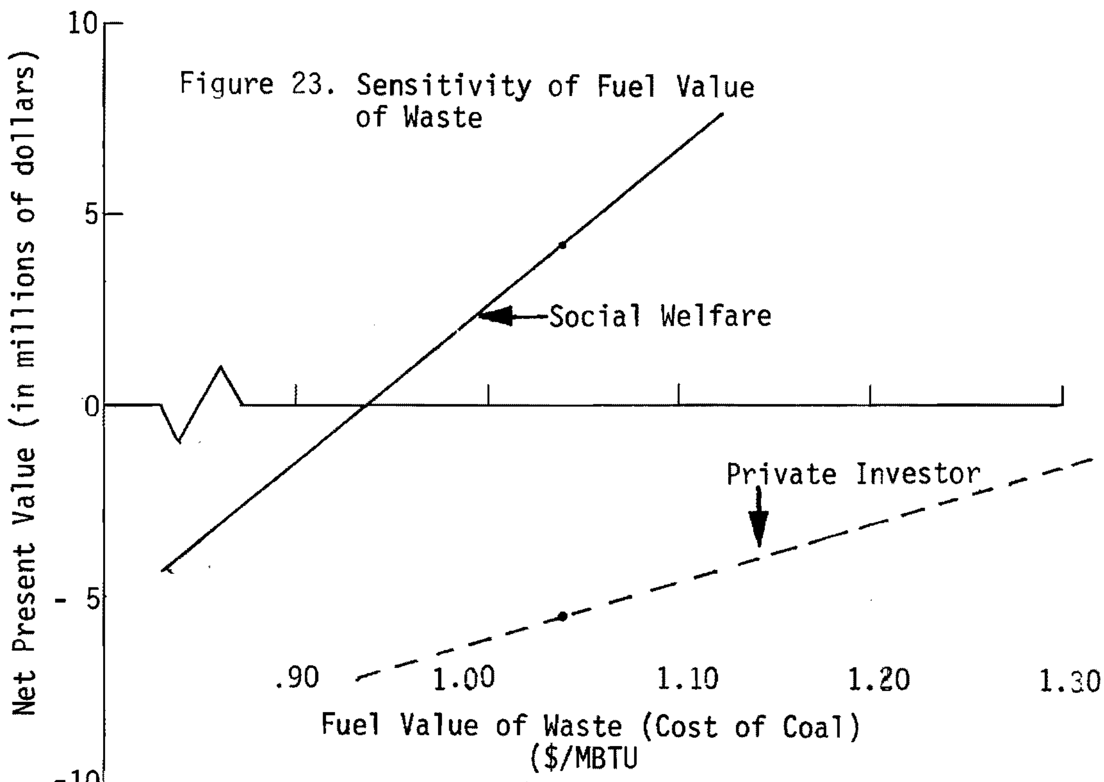


Figure 23. Sensitivity of Fuel Value of Waste

Figure 24

Rate of Cost Increase for Landfills

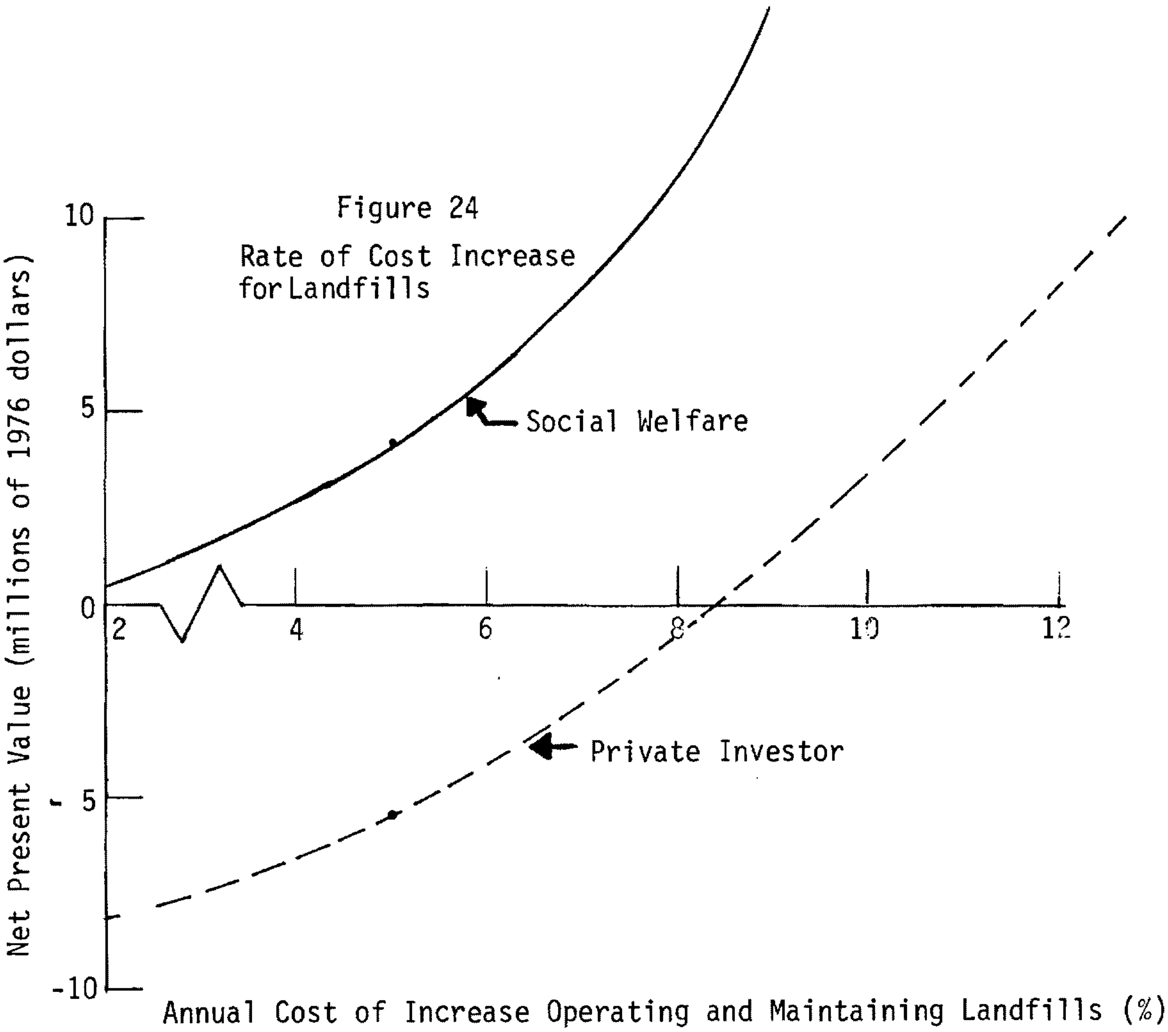
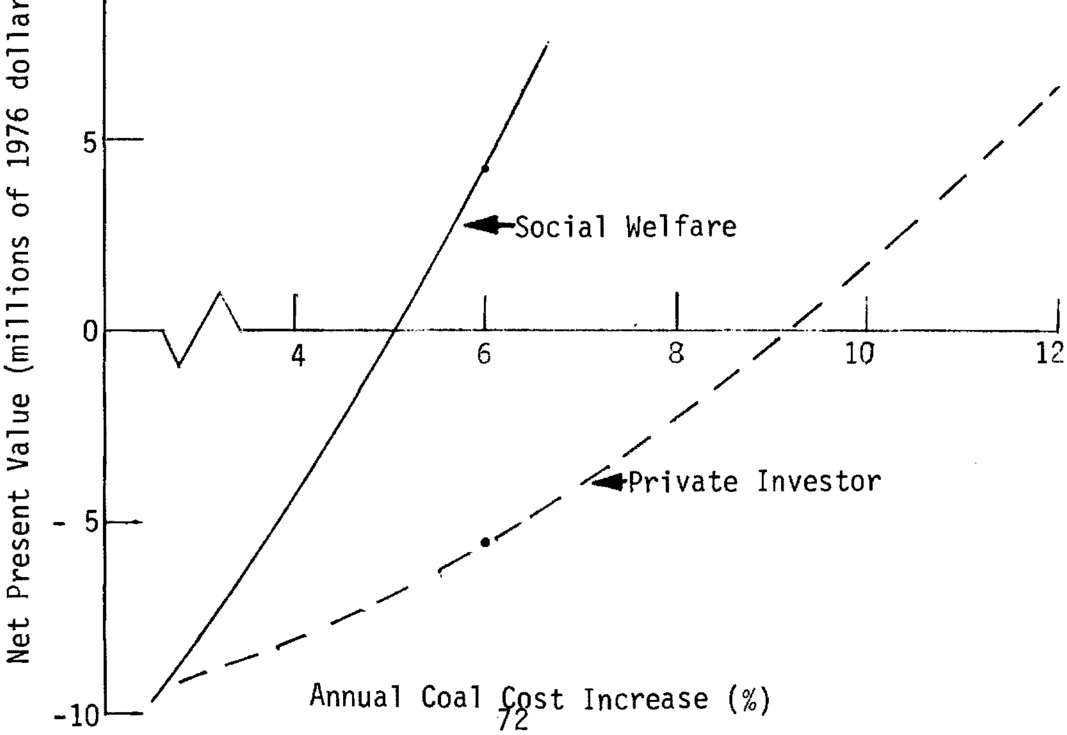


Figure 25.

Rate of Cost Increase of Coal



to increase 9.4% annually. Looking at the recent past (in which coal prices jumped from $10 to $24 per ton in many instances), the 9.4% rate of increase is within the realm of possibilities.

Figures 26 and 27 show the effect of changes in discounting variables (discount rate and lifetime of facility) on the NPV of the WFFHS. The sensitivity curves of the discount rates (the private discount rate is the ROI) are notable in that their slopes have opposite signs. This is due to the time at which the capital costs of the facility are paid. In the societal welfare analysis, capital investment was counted as an initial expenditure; thus, a lower discount rate would make the investment appear more attractive due to the higher value given to future benefits. According to Figure 26, a discount rate of 8.4% produces breakeven conditions. As discussed previously it is difficult to assign a value to the social discount rate, which typically ranges from 0% to 10%. Due to recent concerns about medium-long range resource shortages, the discount rate will probably decrease rather than increase. Therefore, an 8.4% value is less likely than the lower 7% value.

In the private investor analysis, however, the capital expenditure is financed and the principal is not paid for twenty years. A high discount rate gives less value to the large future expense and more value to benefits received in earlier years. The cash flow for the private investor analysis, shown in Table 19, reveals that benefits are accrued only in intermediate years. In the early years of the project, high operating, maintenance and interest costs overshadow benefits received; in the final year, the large principal on the capital investment must be repaid. The NPV is thus penalized with either a high or low discount rate and is relatively insensitive to changes in that rate (as shown in Figure 26).

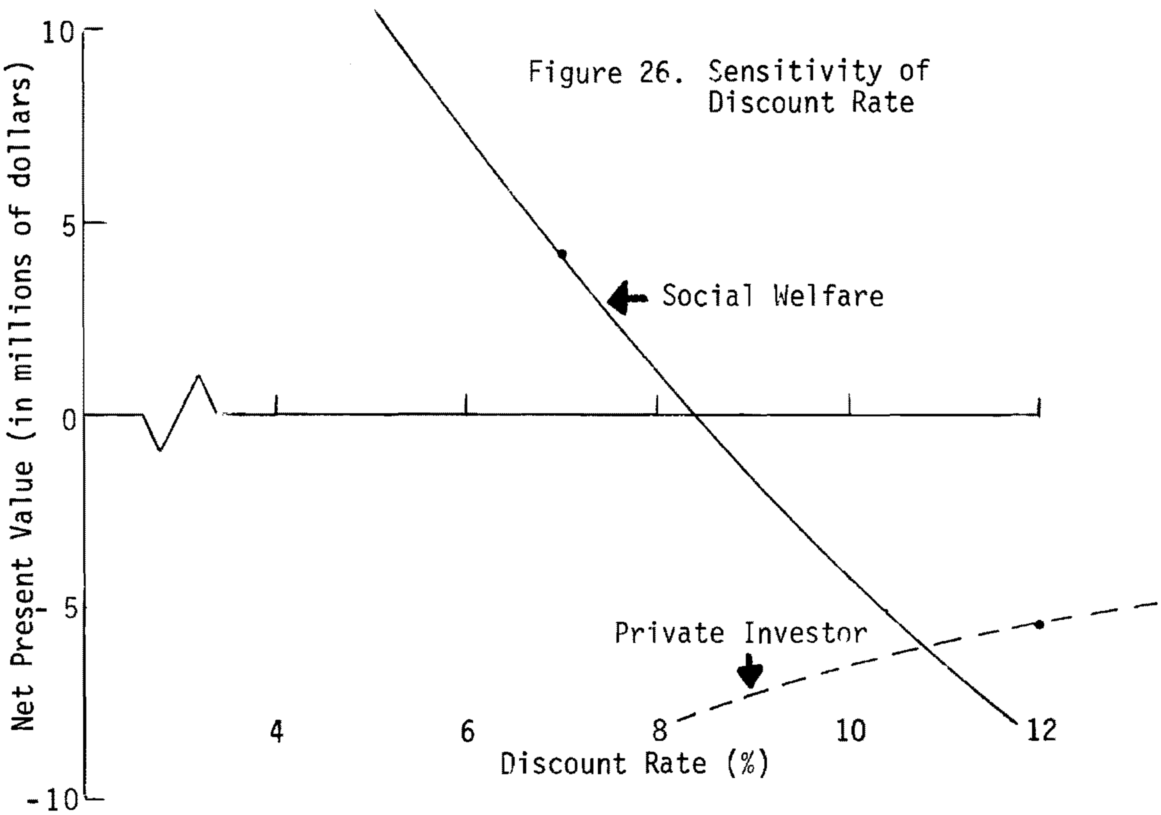


Figure 26. Sensitivity of Discount Rate

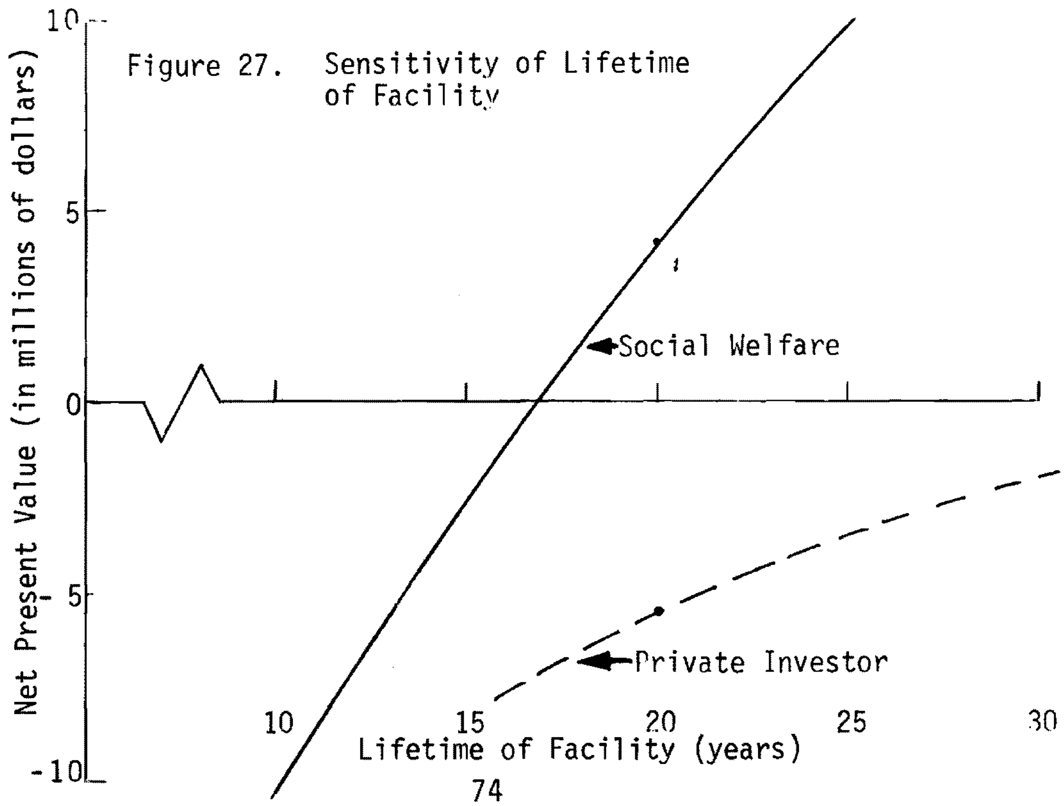


Figure 27. Sensitivity of Lifetime of Facility

Figure 27 shows the effect of the life of WFFHS on its economic attractiveness. The NPV for the societal welfare analysis would be reduced to near zero if the WFFHS operated only 17 years. This reduced lifetime is possible, but it is probable that the plant will operate for longer than the 20 year period assumed in the initial analysis. The private investor would be able to recover his 12% ROI if he could keep the WFFHS operational for 40 years. In actual practice the plant could have a long lifetime, but additional capital replacement costs, not included in the initial analysis, would be encountered.

<u>Aluminum and Glass Recovery</u>. Although the technology for large scale aluminum and glass recovery is not yet commercially available, it is being developed rapidly. Using sensitivity analysis, the range of costs that would make these techniques economically attractive can be estimated. The revenues derived from resource recovery were discussed earlier; they amount to a total of $717,000 during the initial year of operation. It is assumed that an additional $1 per ton operating and maintenance cost is incurred by the use of the aluminum and glass recovery equipment. The breakeven capital cost, as shown in Figure 28, is the point at which the NPV equals the NPV calculated in the initial analysis. At this point, the capital costs of the recovery equipment in the societal analysis could be 9.5 million dollars and in the private analysis could be 5.4 million dollars. Both costs are probably substantially greater than the actual equipment will be, once it is developed. For example, a ferrous metal separator costs only $42,000 and an air classifier costs $260,000. A cost of 1.5 million dollars for a combined aluminum and glass recovery system seems to be a reasonable value. If equipment could be installed at this cost, the societal NPV would increase 186% (to $12.1 million). The private NPV would increase 42% (to

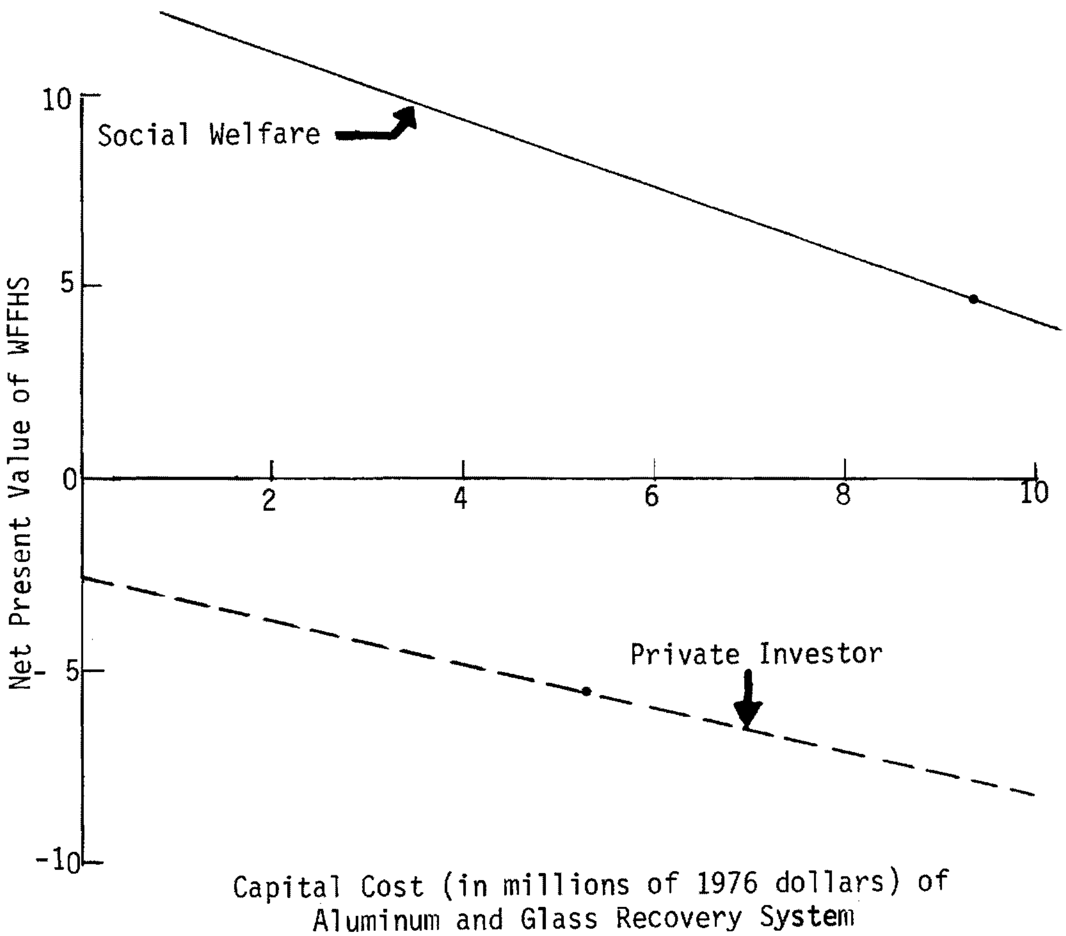


Figure 28. Sensitivity of Capital Costs of Aluminum and Glass Recovery Equipment

-3.2 million). Under the assumptions made, however, the recovery equipment could never be sufficiently inexpensive to make the private NPV positive.

Discussion of Policy Options

One way to bring the societal viewpoint and private viewpoint into closer agreement, is to examine policy options. The purpose of these policies would be to provide incentive for private investors to build WFFHS, so that both the investor and society as a whole may benefit. In the case of the WFFHS, the following policy options can be considered:

(1) Providing low interest (7%) loans to the investor

(2) Giving the investor exemption from additional air pollution control equipment (no additional electrostatic precipitators)

(3) Allowing the investor a tax break (from 48% to 25%)

(4) Establishing a floor on the fuel value of the processed waste ($1.40/MBTU)

(5) Support research in aluminum and glass recovery technologies.

Combinations of these policies were evaluated using cost benefit analysis from the private viewpoint. The results of this analysis are shown in Table 21.

An important consideration in evaluating the policy is the cost to society of implementing the policy. The most obvious cost is the tax money required to pay for the personnel who will administer the policy. If the cost of a given policy drives the net present value of the project itself negative, then another option should be selected. An analysis of this aspect of the policy options was not undertaken during the study.

Table 21

Evaluations of Policy Options

Option	New Private Investor NPV (1000 dollars)
1. Low Interest Loans	-2323.98
2. Exemption from Air Emission Controls	-1528.17
3. Tax Break	-3355.13
4. Floor on Fuel Value	-3119.56
5. Aluminum and Glass Recovery R&D	-3054.26
Combination of Policies	
1 and 2	1204.29
1 and 3	- 153.60
2 and 3	1734.19
1, 2, and 3	4466.65
1 and 4	114.99
2 and 4	81.97
3 and 4	240.21
1 and 5	344.91
2 and 5	943.08
3 and 5	494.04
4 and 5	-2898.00

Net Energy Analysis of WFFHS

Net Energy Analysis (NEA) is a relatively controversial technique that may be applied in analyzing alternative energy projects. NEA provides a measure of the relative efficiency of an energy alternative in providing energy to the nation.

The basic philosophy of Net Energy Analysis is that all commodities, buildings, spaceships, etc. contain an energy investment equivalent to the energy expended in manufacturing them. Of course, all intermediate products that are combined to form a final product have an energy investment which becomes part of the total energy investment contained within the final product. Net Energy Analysis provides the means for the analyst to extract the energy investment in a product, process, service, etc.

The primary criticism of this technique is its use as a means of describing the value of a product. This "energy theory of value" has been condemned in two recent editorials in Science (April 2, 1976, pp. 8, 11). Martha Gilleland, who earlier wrote an article describing use of Net Energy Analysis (Science, Sept. 26, 1975), was very cautious of the concept of an energy theory of value. Berry (4) contends, however, that "If the economists in the market place were to determine their shortages by looking further and further into the future, these estimates would come closer and closer to the estimates made by their colleagues, the thermodynamicists."

This section does not delve into the nuances of price theory but, instead, examines how Net Energy Analysis can be used as a tool for energy policy decision makers. One assumes that the primary mission of energy policy is to guarantee that current and future generations have an adequate supply of energy (meaning that it is available at reasonable cost and that survival is not threatened by potential shortages). The policy maker's objective is to maximize future energy supply, within certain constraints, through actions such as research and development programs, conservation policies, incentive plans, etc. Net Energy Analysis would provide a valuable measure for this policy maker to use. The major benefits of this analysis are as follows:

1) It provides information about the total energy impact of policies.
2) It values energy resources as capital items.
3) It assigns equal value to a given resource whether used now or in the future, given the same technology.

The major detriments of Net Energy Analysis are as follows:

1) Some factors are difficult to quantify, as with the use of dollars.
2) Short term shortages and surpluses are not considered since all products produced in a short term sense will have equal energy value.
3) Data is often collected on an aggregate level, and accurate estimates of the energy investment in specific products are difficult to obtain.

The methodology utilized by the authors to perform the net energy analysis was based in part on a report by Herendeen and Bullard entitled Energy Cost of Goods and Services, 1963 and 1967. The report describes a method for computing the energy cost contained within the spectrum of consumer goods and services defined by a 357 economic sector model of the United States. Energy cost is defined in the report as "all fossil, hydro or nuclear energy consumed along the chain of extraction-refining-fabrication-sales."

The basic methodology uses techniques of Input/Output Analysis to characterize all transactions between sectors in energy terms. Imports and exports are included in the model. The final result of Herendeen and Bullard's study is a set of energy coefficients that reveals the energy investment in each of the 357 economic sectors analyzed. The energy investment is computed for the following energy forms: coal, crude petroleum, refined petroleum, electricity, natural gas and total primary energy. For example, according to Herendeen and Bullard's results, the energy investment in photographic equipment in 1967 was 13,834 BTU of coal, 30,306 BTU of crude oil, 9,604 BTU of refined petroleum, 4,460 BTU of electricity, 19,513 BTU of gas and 46,980 BTU of primary energy per dollar required to manufacture that equipment. A camera that cost $50 to produce in 1967 would have an energy investment of about 2.35 million BTU (MBTU) of primary energy.

Using the 1967 energy investment coefficients, one can compare two alternative energy projects. The analysis included here compares the baseline and waste hybrid alternatives that were introduced earlier. These options can be evaluated by considering the extra capital and operating energy required for the waste hybrid, and comparing this energy investment with the energy returns from using solid waste-derived fuel to replace coal and from recycling ferrous scrap metal. Table 22 displays energy coefficients for pertinent economic sectors in this Net Energy Analysis.

The average energy investment in equipment used in a waste processing plant was computed, using cost estimates obtained from manufacturers. Table 23 shows the results of this analysis. All costs were current and had to be converted to 1967 costs. The conversion factor used was the Marshall-Stevens Equipment Cost Index, which is displayed in Chemical Engineering. Each type of equipment was coded by economic sector. One major source of error is the relatively high level or aggregation, even at the 4-digit ID code level. For example, ID Sector 4806 (Special Industry Machinery, not Elsewhere Classified) includes jeweler's machines, paint making machines, wallpaper trimmers, kilns, and shoe making machines. These machines may possess quite different energy investments even though they are characterized by the same energy coefficient. Once the ID sector has been identified, the energy investment can be approximated using the cost and energy coefficient for that equipment. Costs of transportation (by truck) and installation also were estimated and included in the analysis. The table shows that the average energy investment in installed waste processing equipment was 59,842 BTU/$(1967).

Table 24 displays estimates of the energy investment in capital components of the WFFHS. The procedure is identical to that used to find the energy investment in equipment. Table 25 shows the equivalent energy consumed annually in operating the facility. Table 26 estimates the energy returns of the WFFHS. The figure for ferrous scrap is a very crude estimate which is quite small when compared to the energy returns from the solid waste derived fuel. Table 27

Table 22: Energy Coefficients of Pertinent ID sectors and SIC codes[1]

Standard Industrial Classification (SIC) Code	Description	ID Sectors[2]	Energy Coefficient (BTU/1967 $)
1011	Iron Ore Mining	500	127,708
121	Coal Mining	700	1.0068 BTU/BTU
1621	New Construction-Nonresidential	1102	67,206
1611	New Construction-Highways	1104	117,400
17	Maintenance-Construction-Other	1202	57,108
3391	Iron and Steel Forging	4211	104,153
3531	Construction Machinery	4501	68,040
3535	Conveyors	4602	64,339
3559	Special Industrial Machinery	4806	58,614
3564	Blowers	4903	62,346
3621	Motors, Generators	5304	62,724
3711, 3714	Motor Vehicles and Parts	5903	66,762
4212	Local Transportation	6502	66,965
4213	Motor Freight Transportation	6503	46,188
4911	Electric Utility	6801	3.7963 BTU/BTU
7391	Miscellaneous Business Service	7301	26,996
7538	Auto Repair	7500	49,141

[1] Robert A. Herendeen and Clark W. Bullard, III, Energy Cost of Goods and Services, 1963 and 1967, Center for Advanced Computation, University of Illinois, Nov. 1974.

[2] Herendeen and Bullard's study described economic sectors by these ID codes instead of using SIC codes.

Table 23: Energy Investments in Equipment
(1000 ton/Day Plant)

Equipment	ID Sector	SIC Code	Cost	Cost Index	Energy Coefficient	Energy Investment
			(1976 $)	1967-1975	(BTU/$)	MBTU
Air Classifier	4903	3564	$260,000	1.8	62,346	9006
Ferrous Metal Separator	4806	3559	$ 42,400	1.8	58,614	1381
Conveyors	4602	3535	$250,000	1.8	64,339	8936
Hammermill (Primary)	4806	3559	$250,000	1.8	58,614	8141
Electric Motors	5304	3621	$ 90,000	1.8	62,724	3136
Hammermill (Secondary)	4806	3559	$110,000	1.8	58,614	3582
SUBTOTALS			$1,012,000		**60,798**	34,182 MBTU
Transportation (5% of cost)	6503		$ 50,600	1.8	46,188 Truck	1298
Installation (10%)	1202		$101,200	1.8	57,108	3211
TOTALS			$1,163,800		59,842	38,691 MBTU

Cost Component	ID Sector[1]	Cost Estimate (Index to 1967 is 1.8)	Energy Coefficient (BTU/1967 $)	Energy Investment (Billion BTU)
Processing Plant				
Land & Site Work	1104	$ 532	117,400	62
Building Foundations	1102	1,862	67,206	125
Equipment (Installed)		3,014	59,842[2]	180
Mechanical	1102	355	67,206	24
Electrical	1102	886	67,206	60
Vehicular Equipment	5903	289	66,762	19
Engineering, Admn., etc.	7303	1,762	24,991	44
Subtotal		$8,700		514
Utility				
Mechanical	1102	31	67,206	2
Electrical	1102	116	67,206	8
Equipment (Installed)		3,481	67,307[3]	234
Engineering, Admn., etc.	7303	962	24,991	24
Subtotal		$4,590		268
Transport, Delivery and Distribution				
Equipment	4501	228	68,040	15
Engineering, Admn., etc.	7303	48	24,991	2
Subtotal		276		17
TOTAL		$13,566		799 Billion BTU

1. See Table 22.
2. See Table 23 for derivation of energy coefficient.
3. Average of Sectors 4208, 4602, and 4903.

Table 25: Results of Net Energy Analysis: Annual Operating Energy

Cost Component	ID Sector[1]	Cost Estimate (1967 $) (Index to 1967) is 1.8)	Energy Coefficient (BTU/1967 $)	Energy Investment (Billion BTU)
Processing Plant				
Administrative		$ 8		0[4]
Operating Labor		225		0
Maintenance Labor		60		0
Maintenance Materials	4211	76	104,153	7.93
Utilities	6801	179[2] (81.3 B BTU)	3.7963 BTU/BTU	308.60
Equipment Replacement		56	59,842	3.35
Miscellaneous Expense	1102	25	67,206	1.68
Residue Disposal	6502	163	66,965	10.90
Front End Loader Maintenance	7500	54	49,141	3.16
Subtotal		845		335.62
Utility				
Operating Labor		91		0
Maintenance Labor		87		0
Maintenance Materials	4211	20	104,153	2.06
Power	6801	66 (30 B BTU)	3.7963 BTU/BTU	113.93
Incremental Ash Disposal	6502	13	66,965	.90
Laboratory Analysis	7301	44	26,996	1.19
Subtotal		321		118.08
Transport, Delivery and Distribution				
Administration		1		0
Operating Labor		56		0
Vehicle Expense		28	233,206	6.51
Subtotal		85		6.51
TOTAL		$1,251		460.21

1. See Table 22.
2. Assume cost of energy is .75¢/KWH.
3. Based on estimated energy upkeep for car (from Herendeen and Bullard).
4. The energy investment in labor is not considered in this analysis since people would consume approximately the same amount of energy regardless of their employment by the WFFHS.

Table 26: Results of Net Energy Analysis:Annual Energy Returns

	ID Sector	Tons/Year	Value/Ton	Energy Coefficient	Energy Investment (Billion BTU)
WASTE-DERIVED SOLID FUEL	700	182,000	11 MBTU/Ton	1.0068 BTU	2,015.6
FERROUS METAL RECOVERY	500	20,800	$4/Ton[1]	127,708 BTU/$	10.6
					2,026.2 Billion BTU

[1]Estimated value of recovering ferrous metal based on the following assumptions:

1) 1 ton of scrap is equivalent in the steel making process to 1 ton of iron ore, energy savings are 127,708 BTU/$.
2) 1 ton of iron ore cost $4/ton in 1967 (rough estimate).

Table 27: Results of Net Energy Analysis: Summary (Billion BTU's)

Annual Operating Energy	460
Annual Energy Returns	2,026
Net Annual Returns	1,566
Capital Energy (Divided over 20 years)	40
Net Energy	1,526 Billion BTU/year

Payback Period ~ ½ year

shows the final results of this preliminary analysis. The WFFHS is very energy efficient. On the average, it yields a net return of 1526 Billion BTU per year. The capital energy investment of 799 Billion BTU would be repaid in less than one year.

Alternative Systems. The following two alternatives to combustion of pulverized waste, pyrolysis and methanation, were investigated during the study. These technologies provide a much more attractive fuel for use in electric power plants from the utility company's viewpoint. Synthetic gas and fuel oil cause less corrosion, produce fewer air emissions, and are easier to transport and store than a pulverized waste fuel. However, the processes involved in producing these fuels are much more complex and costly, and they may produce significant water products, particularly trace metals, at the processing plant. Table 28 shows the results from a Cost Benefit Analysis of three different proposed systems. The capital costs of these facilities, which shred the incoming waste, separate ferrous metal and process the light fraction into a synthetic fuel, differ widely. TVA's system has a high, investment cost but has a correspondingly low operating and maintenance (O&M) cost. The other systems estimate much lower investment costs, but very high O&M costs. The amount of fuel produced by each system, as evidenced by the fuel value of waste, also varies depending on the system. In all cases, the NPV had a very large negative value. Thus, the Solid Waste Fuel System is superior economically to these alternatives.

Site Specific Analysis. The results of the analysis that uses data from specific cities is shown in Table 29. The analysis examines a WFFHS from a societal viewpoint; the methodology and basic parameter values from the initial analysis. The most important observation is that in every location but one, the NPV

Table 28

Cost Benefit Analysis of Alternative Systems[1]

	Rate of Increase	TVA Pyrolysis[2] ($1000)	Pyrolysis Fuel Oil ($1000)[3]	Methanation[4]
CAPITAL COSTS				
Processing Plant	.05	$45,449	$18,634	$14,958
Firing Facility Modification	.05	2,761	2,613	912
Transportation	.05	291	337	124
Subtotal		$48,501	$21,584	$15,994
ANNUAL OPERATING AND MAINTENANCE COSTS				
Processing Plant	.05	$ 2,314	$ 4,116	$ 4,160
Firing Facility Modification	.05	0	183	0
Economic Dispatch Penalty	.05	0	0	0
Transportation	.05	78	124	46
ANNUAL BENEFITS				
Previous Landfill Costs	.05	$ 1,147	$ 1,147	$ 1,147
Ferrous Metal Recovery	.05	416	416	416
Environmental	0	17	12	4
Fuel Value of Waste	.06	2,041	1,587	645
NET PRESENT VALUE		- 28,683	- 42,253	- 51,584
ANTICIPATED BENEFITS IN $/TON PROCESSED		-$10/ton	-$15/ton	-$18/ton

[1]The methodology for this analysis is identical to that shown in Table 18 for the Solid Waste Fuel.

[2]Based on a TVA Study (Reference 42).

[3]Based on Bechtel's Technology Assessment (Reference 3) and Union Carbide's Cost estimate for DeKalb County, Georgia (Reference 43).

[4]Based on a University of Illinois Study (Reference 33).

Table 29

Site Specific Analysis

	Capacity 1000 Tons/yr	to WFFHS (miles)	Landfill Cost ($/ton)	Net Present Value ($1000)	$/Ton
Birmingham	92.3	30	1.40	- 8,669	- 8.62
Mobile	65	20	1.50	- 6,161	- 8.70
Jacksonville	442	144	2.50	-62,835	-13.04
Orlando	100	108	1.60	-17,123	-15.71
Tampa	170	10	2.00**	- 6,199	- 3.35
Atlanta	312	5	2.00	- 3,750	- 1.10
DeKalb County	253	15	6.90	12,788	4.64
Macon	78	5	3.00	- 1,966	- 2.31
Savannah	71.5	10	3.50	- 3,070	- 3.94
Charlotte	337.5	5	2.00	- 3,289	- .89
Fayetteville	31	50	2.00**	- 6,477	-19.17
Raleigh	164.8	30	2.37	- 8,375	- 4.66
Chattanooga	59.5	50	2.00**	- 7,123	-10.98
Knoxville	92.6	20	3.00*	- 4,285	- 4.25
Memphis	78.0	5	1.80	- 5,003	- 5.88
Nashville	51.0	25	2.00**	- 5,057	- 9.10

*County or City Charge to commercial customers.

**Assumed to be $2.00/ton; Data not available.

Landfill costs less than $3/ton are escalated at 7%, those between $3 and $4/ton at 6%, those greater than $4/ton at 5%.

is negative. The results would suggest that the parameter values shown in the initial analysis present an overly optimistic situation for WFFHS implementation.

In all cases but one, landfill costs are significantly less than $4/ton Costs in other areas (e.g.,Milwaukee, Wis., $8.93/ton in 1976 using Consumer Price Index; Ref.9), Louisville, Kentucky, ($4.50/ton in 1977 escalation at 7%; Ref. 21), and Connecticut (larger landfills cost from $1 to $7/ton in 1973; Ref.13), suggest that southeastern landfill costs will increase at a relatively rapid rate. In the analysis, costs under $3/ton are escalated at 7% per year, costs between $3 and $4/ton are escalated at 6% and costs greater than $4/ton are increased 5% annually. Using these escalation factors, in only one location—DeKalb County, Georgia,—are positive benefits derivable from a WFFHS. DeKalb County, a surburban county in the Atlanta metropolitan area, faces severe landfill problems and is, thus, in a position where the WFFHS is an attractive alternative. DeKalb County's situation may be the precursor to problems in other cities. If such problems are imminent, WFFHS may be attractive. For example, if landfill costs rose at a 9.5% annual rate in Atlanta and Charlotte, landfills charges would be $5/ton in 1985 instead of $4/ton. This is not a drastic increase relative to DeKalb County's current $6.90/ton charge. However, under these conditions the NPV for both cities would be positive (equivalent to $.20/ton in Atlanta and $.40/ton in Charlotte).

Conclusions and Recommendations

The investigation into the economic acceptability of Waste Fossil Fuel Hybrid Systems has produced the following conclusions:

- In cases of relatively high landfill costs and relatively close proximity to an adequate power plant for pulverized waste combustion, a WFFHS would yield significant benefits, from a societal viewpoint.

- In almost all cases, a WFFHS would not yield an acceptable Return on Investment to a private investor.

- Rapidly increasing coal prices could bring a high enough price for the pulverized waste fuel to yield positive benefits from either viewpoint.

- An increase in benefits, however, may be balanced by cost overruns and unexpected operating and maintenance problems.

- Development of aluminum and glass recovery techniques would add significantly to the attractiveness of WFFHS. Future shortages of aluminum would add significantly to its value and, thus, to the economic favorability of WFFHS.

- A WFFHS produces significant energy savings. In our analysis the original energy investment is repaid in less than one year.

- Pyrolysis, methanation and other large scale waste processing alternatives are not economically competitive with pulverized waste combustion. Environmental, maintenance, transportation, and storage problems of the utility, however, make these more attractive from a convenience standpoint. Environmental problems of the waste processing techniques, especially pyrolysis, may threaten their feasibility.

- In cases where the societal net present value is positive and the private net present value is negative, policies may be instituted to encourage private investment. In the initial analysis, the most attractive sets of policies are:

  1. Provide low interest loans (7%), and place a floor on the value of waste fuel ($1.40/million BTU).
  2. Exempt WFFHS from controls on particulate emission increases, and place a floor on the value of waste fuel.
  3. Give a tax break (25% instead of 48%) to WFFHS owners, and place a floor value on waste fuel.
  4. Provide low interest loans and promote aluminum and glass recovery Research and Development.
  5. Exempt WFFHS from controls on particulate emission increases, and promote aluminum and glass recovery R&D.
  6. Provide a tax break and promote aluminum and glass recovery R&D.

- Any policy enacted incurs a cost to society; the effect of this cost on the net societal benefits of the WFFHS must be ascertained before any set of policies are implemented. For example, exemption of WFFHS from air emission controls may increase the density of particulates sufficiently to impair human health. Also, some policies, such as the air emission control exemption, may not be politically feasible.

These conclusions reveal that, in some locations, WFFHS may be a solution to specific problems; however, this type of waste processing is by no means a panacea for the overall nationwide problem. One partial solution not addressed in the study is Source Separation. The rationale for its omission is that it does not pertain to power systems, the main focus of this study. Source separation, which is a decentralized, consumer processing of waste into various categories (paper, aluminum, steel, clear glass, etc.), provides a purer product and virtual elimination of the high investment costs associated with centralized waste processing. This type of waste disposal provides energy savings in that energy used in mining and purifying raw materials for aluminum and steel production can be reduced. Source separation places more of the cost of waste disposal on the consumer, in terms of his time.

A major consideration not addressed at length in this study is the institutions to be involved in WFFHS and their interrelationships. The institutions themselves, or their inability to interact with one another, may inhibit or prevent development of WFFHS. There are several institutions that may play a part in the design, development, construction, and operation of a WFFHS; the major ones are as follows:

- Local citizenry (voting population)
- Local government
- Electric Utility
    - Public Service Commission
    - Independent waste-disposal/collection/processing equipment
- Manufacturer
    - Recycling markets
    - U.S. and State Environmental Protection Agency
    - Environmental and Consumer Groups

An examination of the complex series of events, decisions and agreements that must be made before a WFFHS can begin operation is beyond the scope of this study. However, a few examples of actual situations may give some insight into the types of problems that can occur. Some utility companies (e.g., Union Electric in St. Louis) have actively developed WFFHS; others (e.g., Wisconsin Electric Power Co. in Milwaukee) have supported development and worked with planners of WFFHS to characterize the utilities' role. However, some utilities (e.g., Georgia Power Company and TVA) have investigated WFFHS and decided not to pursue their development. Georgia Power Company cited such unresolved questions as the effects of solid waste fuel combustion on efficiency of Electro-Static Precipitators, overall power generation efficiency, sulfur dioxide emissions and boiler tube corrosion in its decision not to burn a solid fuel. GPC did state its willingness, however, to burn a pyrolysis-derived low-BTU gas. One of the main constraints to utility participation in WFFHS is the existence of these unanswered questions. This resolution will determine the future of WFFHS.

Local government institutional problems center on the government official's perception of the electorate's viewpoint and what he or she feels is in the best interests of his constituency. Differences in opinion among members of the county commission or other governing body may impede development. The local sanitation department may oppose proposals from WFFHS exponents and use its influence to forestall progress. In making a decision, the governing body must often balance conflicting sets of data; thus, a reliable data base from which it could draw is very important.

Some aspects of institutional problems are discussed in greater detail in Working Paper II (See Appendix A). At this point in time, no adequate investigation into these problems has been made. This type of study would aid in alleviating these problems in the future and promoting sound, consistent procedures for waste processing, recycling and disposal.

Specific recommendations of the study team are as follows:

- Identify those communities where waste disposal may be a severe problem in the future.

- In cases in which the benefits of WFFHS outweigh the costs, propose and evaluate policy measures needed to give incentive for construction of WFFHS. Of course, municipal ownership is an alternative to private development, but federal government support, both technical and financial, may be needed.

- A thorough evaluation of the institutional problems associated with WFFHS development should be undertaken. A number of different actions taken by diverse groups can block implementation of this type of system. In many cases, these actions may impede a project that is in the public interest. Avenues that can be taken to overcome these institutional constraints should be developed and disseminated.

- Accurate and standardized data collection and accounting procedures are needed in solid waste disposal sections of local governments. Planning departments should be developed to perceive potential future problems (e.g., shortages of landfill space) and to propose solutions (e.g., WFFHS, Source Separation).

- Unresolved technical questions, particularly those relating to the effects of solid waste fuel combustion on boiler tube corrosion and air emissions should be addressed. Information as to their resolution should be disseminated widely.

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V. MULTIPLE-USE SYSTEMS

Multiple-use systems involve the carefully planned grouping of industrial, residential/commercial and/or agricultural activities in complexes that can provide mutually beneficial utilization of energy, raw materials, co-products, land, plant wastes and transportation facilities, and promote greater economical attractiveness of pollution-control measures, resource recovery, etc. Practically achievable multiple use approaches to industrial site planning and plant design offer the promise of some very exciting possibilities for the solution of major national and international problems, such as food supply, energy resources and conservation, environmental quality and land use.

A firm basis for multiple use systems has been established by Isard (11-17), Czamanski (5,21), the U.S. Atomic Energy Commission (1,10,18,19) and others. The concept has been discussed in the literature under various names, such as Industrial Complexes (Isard 12, Czamanski 21), Nuplexes (AEC 10), Decoplexes (Conway 2-4), Industrial Parks (AEC 18), Federal Energy Administration, and others) and Modular Integrated Utility Systems (MIUS). Isard and co-workers, in the nineteen-fifties, pioneered the method of industrial complex analysis in investigating a petrochemical complex for Puerto Rico (13). Recently, Isard (17) extended this method to include environmental management activities, with specific reference to a proposed coal power-plant complex in New York State. The AEC has published a number of reports and papers concerning investigations of industrial and agro-industrial complexes centered around nuclear reactors. These complexes are typically designated as "nuplexes," an acronym derived from <u>nu</u>clear com<u>plexes</u>. Conway has focused his attention on decoplexes, a term derived from development/ecology/complexes, which emphasize the grouping of related industries around waste-treatment plants. Many petroleum and chemical companies use variations of industrial complex analysis in planning and developing their plant sites. In fact, at the present time there are many economically sound and well-integrated industrial complexes in operation in this country and abroad. An important example is the Dow Chemical Plant in Midland, Michigan, which receives thermal energy from a nearby nuclear power plant operated by Consumers Power Company.

In this study, the project staff concentrated on the energy supply systems in a multiple-use complex. Several postulated multiple-use systems, which reflect a range of centralized and decentralized options, were evaluated in terms of economics and energy savings. Potential economic benefits were evaluated using Cost-Benefit Analysis. Energy savings were derived on both a fuel-specific and overall efficiency basis.

Postulated System

The basic structure for a multiple-use system is depicted in Figure 29. The industrial sector may be comprised of one very large plant, or combinations of different plants. For the analysis presented here, four plants were chosen--chlorine caustic soda plant, ammonia plant, pulp and paper plant, and a phosphoric acid plant. The output of each plant was assumed to be 1000 tons per day, except for the pulp and paper plant which produced 2000 tons per day. These plants were selected because of their potential to use steam extracted from the power plant's turbines. The thermal and electrical energy requirements of each plant are shown in

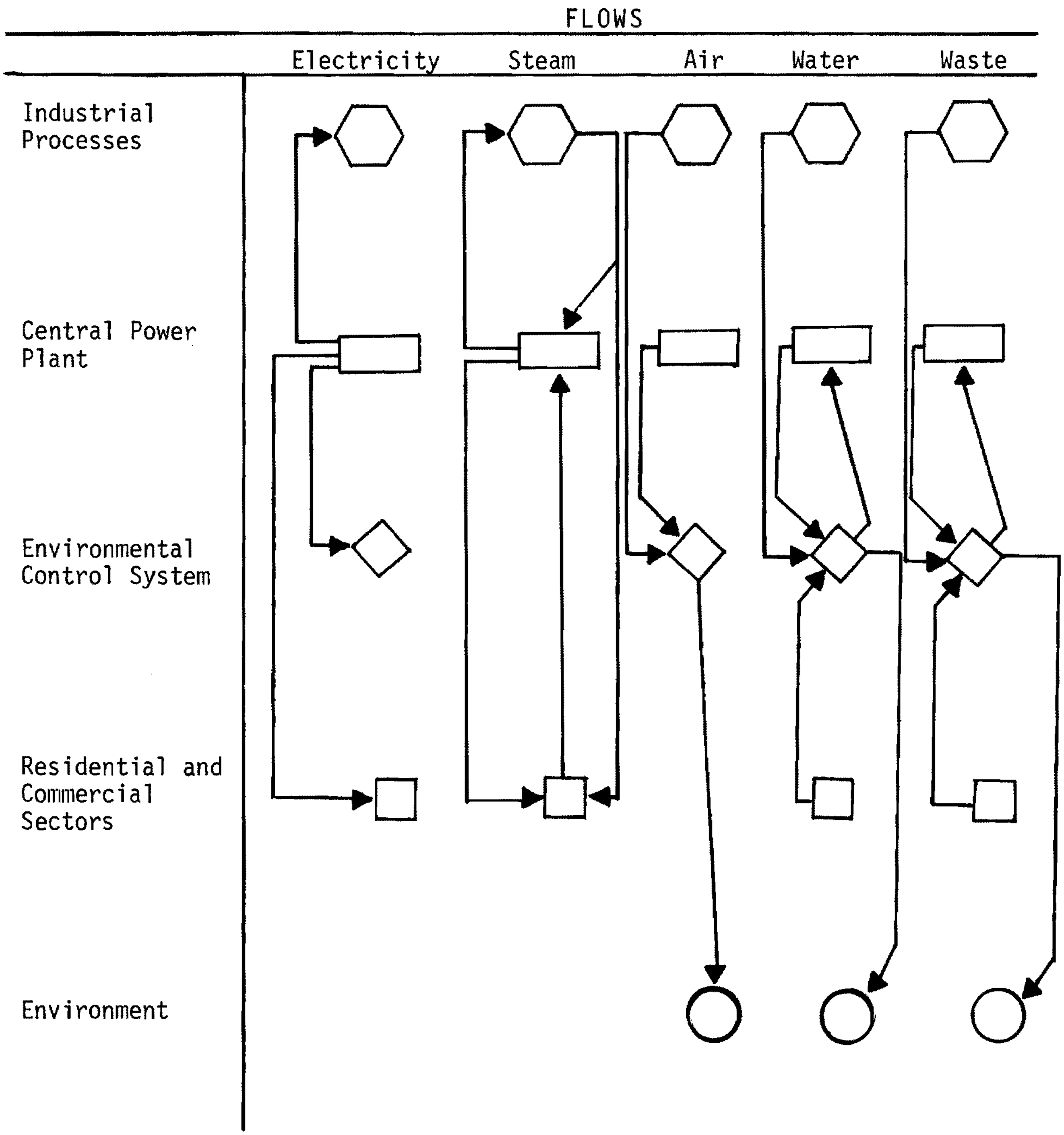


Figure 29. Basic Structure of a Multiple-Use System

Table 30.

The utility power plant postulated to supply energy to the industries is a 1000 MW coal-fired plant. Figure 30 describes the flow of steam through the turbines and the points at which steam may be extracted for industrial use. At A, the cold reheat point, steam for energy intensive process heat uses can be extracted; at B, the crossover point, steam used in less intensive operations can be obtained. The steam requirements of industry must be matched with steam quality at the extraction points in the utility power plant. Also, steam volume transported to the industries should be augmented to compensate for energy losses over distance. The losses in this example were estimated to be 10%. Table 31 displays the flow rate of steam required at the two extraction points in the utility plant to meet each industry's thermal energy needs.

Several possible systems can be designed to supply the electrical and thermal needs of the four industries; three options are described below:

1) Status Quo Approach--In this system, the utility provides only electrical power for industrial use. Industrial power systems provide the required steam. The utility plant also provides electricity to other uses in the regular utility network.

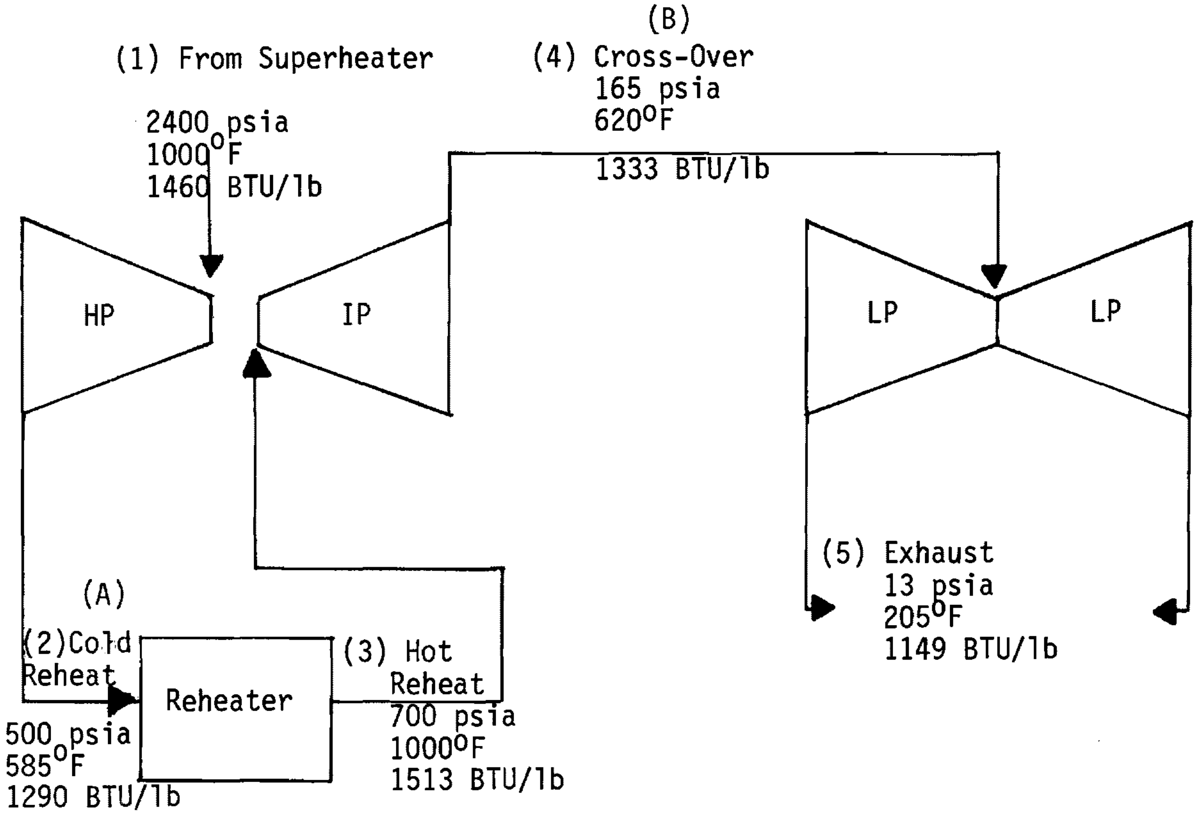
2) Decentralized Multiple-Use Approach--In this system, all power systems for industrial energy needs are located in the industry. A smaller utility plant provides electricity for the utility network.

3) Centralized Multiple-Use Approach--In this system, all power needs are met by the coal-fired utility plant.

Figure 31 depicts the electricity and steam flows, as well as the power plant locations for the three cases. In Case 2, industrial power plants produce by-product electric power which is used within the industrial complex. Excess power is sold back to the grid. In Case 3, the utility

Table 30. Electrical and Thermal Energy Requirements of Industrial Processes

	Capacity (tons/day)	Thermal Needs (lbs/hr)	Thermal Characteristics P(psia)	T(^{o}F)	Electrical Needs (MW)
Chlorine-Caustic Soda	1000	480,000	30	550	130
Ammonia	1000	420,000	450	700	1.3
Pulp and Paper	2000	210,000	475	705	94
		625,000	165	425	
		370,000	65	335	
Phosphoric Acid	1000	2,940	100	450	7.6
		155,000	12	275	



Change in enthalpy between states		Efficiency of Conversion
(1) - (2)	170 BTU/lb	.919
(3) - (4)	180 BTU/lb	.90
(4) - (5)	184 BTU/lb	.875

HP - High Pressure Turbine

IP - Intermediate Pressure Turbine

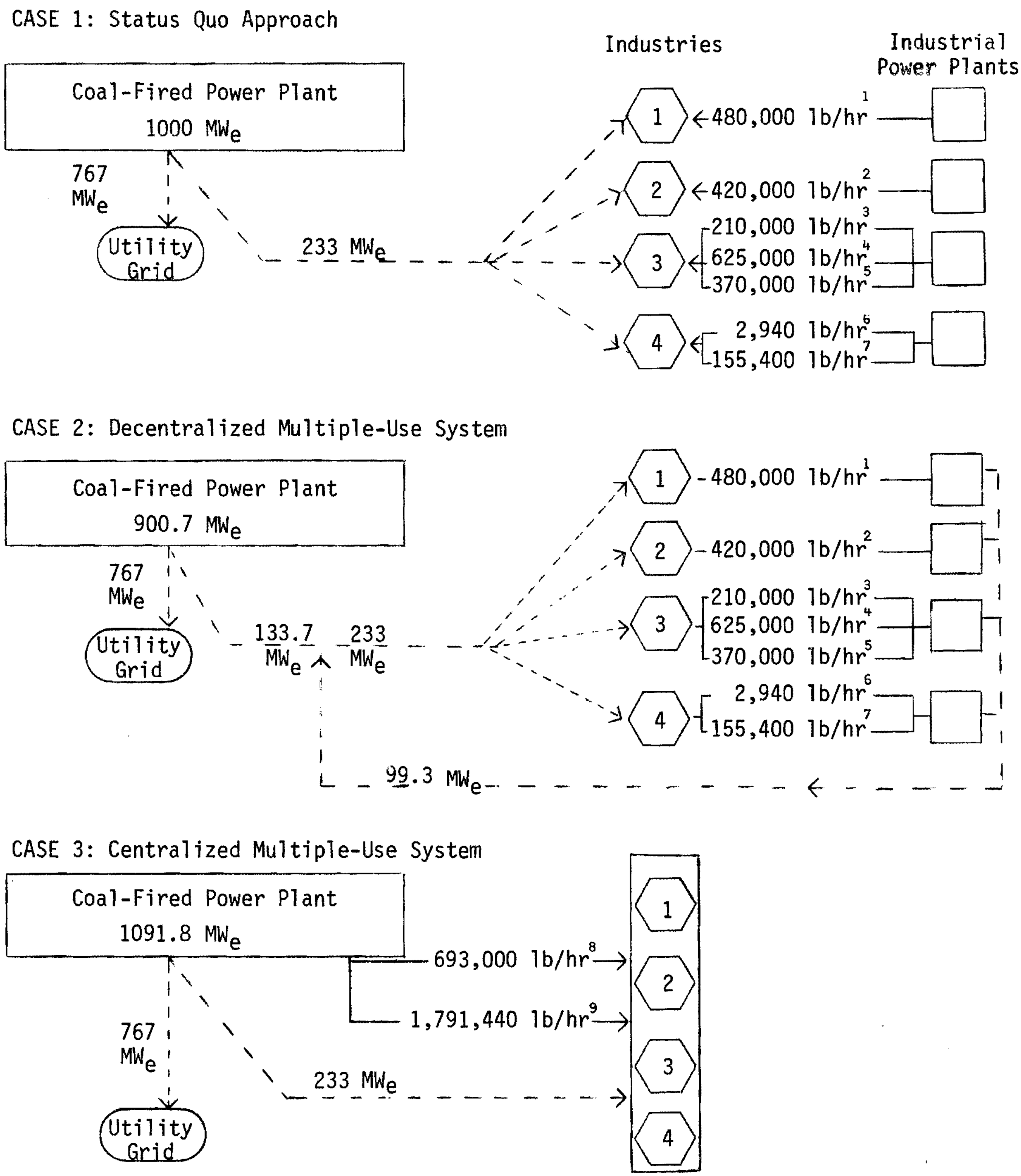
LP - Low Pressure Turbine

Figure 30. Typical Steam Flow in a Coal-Fired Generating Plant

Table 31. Industry/Utility Steam Matching for Case 3

	Distance to Utility Power Plant (miles)	Utility Plant Steam Flow (lbs/hr) Cold Reheat (500 psia, 585°F)	Cross-Over (165 psia, 640°F)
Chlorine-Caustic Soda	1.5		552,000
Ammonia	3.0	546,000	
Pulp and Paper	1.5	241,000	1,216,540
Phosphoric Acid	3.0[1]		201,500
TOTAL		787,500	1,970,040

[1]It is assumed that an additional 10% of steam flow is needed per mile transported.



Steam Characterisics

1. 30 psia, 500°F
2. 450 psia, 700°F
3. 475 psia, 705°F
4. 165 psia, 425°F
5. 65 psia, 335°F
6. 100 psia, 450°F
7. 12 psia, 275°F
8. 725 psia, 590°F
9. 167 psia, 665°F

Figure 31. Diagrams of the Three Postulated Systems

power plant must produce steam as well as electricity; in order to meet all demands it must be larger than utility power plants in the other classes.

Other Design Considerations

One of the most important parameters to address is reliability. It is highly unlikely that the downtimes for both industries and power plant will coincide; thus, a single power plant cannot guarantee to provide the industrial process steam whenever demanded. Two possible solutions are evident to overcome this problem--1) a back-up system may be installed, either in the utility or in the industries, or 2) the industrial plants may agree on an interruptible thermal energy supply.

In the example, a back-up system was assumed to exist at the utility. This system would take steam from the "throttle" of a unit adjacent to the unit in which steam is normally extracted. Steam taken from this point is primary steam at 2400 psia and $1000^{o}F$. This back-up system is identical to that discussed in a General Electric study, done for National Science Foundation, entitled Assessment of Dispersed Electric Generation vs. Nuclear Power Parks.

Another point of concern is the water cycling system. In an open system, the steam would be transported to the industries, where it would be condensed and cooled, and then returned to the environment. In a closed system, the steam would be condensed by the industry but then returned to the utility power plant. This condensate must have remained of acceptable purity through the industrial processes, or it would not be suitable for utility boiler feedwater. Some industries may contaminate the steam, and, thus, a closed system would not be feasible. In the ammonia industry, which is an extreme example, steam combines directly with other raw materials in the reaction process.

For the sake of simplicity, we assumed an open system in our example. Additional feed water make-up requirements would be necessary at the utility as well as cooling systems at the industries. Smaller cooling systems would be needed at the utility.

Economic Parameters

In order to analyze the three cases, values for the following parameters must be estimated:

Capital Costs, and Operating and Maintenance Costs:
- Utility Power Plant
- Industrial Power Plant
- Steam Extraction and Piping Systems
- Feedwater Make-up Systems
- Cooling Systems

Fuel Costs:
- Utility Power Plant
- Industrial Power Plant

The estimates used for these costs were obtained from pertinent literature sources. Estimates for several costs were not available and reasonable figures were hypothesized by the project staff. A sensitivity analysis was performed to determine the range of values in which multiple-use systems were favorable.

Capital Costs. Figure 32 shows the range of coal-fired power plant capital cost estimates obtained from the literature survey. These estimates represent the cost of coal-fired power plants with sulfur-dioxide scrubbers installed. The line plotted through the data points is the least squares regression of the capital cost in each year. This line was used as the estimator for these costs. The rate of cost increase defined by the line is 7.87% per year. The size of a basic unit was assumed to be 1000 MW,

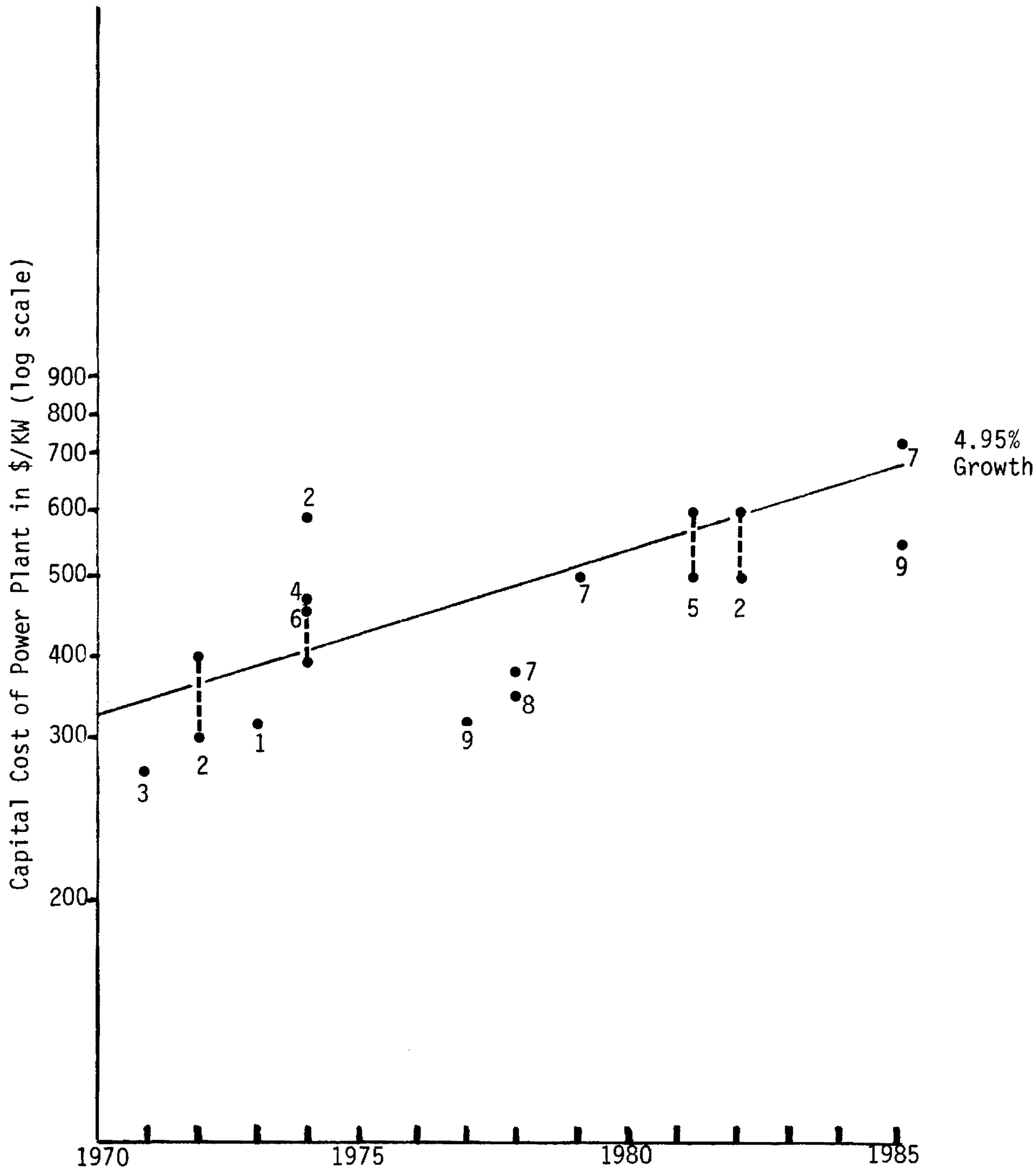


Figure 32: Coal-Fired Power Plant—Capital Cost Estimates

Sources listed on page 111 provided data for Figure 32.

Sources for Figure 32

1. Unpublished Report.

2. Booth, H. R., R. D. Ehri, F. J. Keneshea, P. P. Knecht, H. Lawroski, R. L. Naymark, A. G. Silvester, and W. R. Thompson, "Nuclear Power Today," Nuclear Services Corporation.

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as this was the capacity used in the majority of the literature source estimates. An economy of scale exponent of .7 was used to calculate the cost of larger and smaller units. The formula for estimating the cost of a coal-fired unit was as follows:

$$CC = (BC)\left(\frac{CAP}{1000}\right)^{.7}(1 + RCI)^{(1985-CONY)}$$

where

CC = Capital Cost of the plant in the year construction begins

BC = Cost of the base plant (1000 MW plant built in 1985)

CAP = Capacity of the proposed plant

RCI = Rate of cost increase (7.87%)

CONY = Year in which construction begins

Figure 33, which estimates the capital cost of industrial boilers, was derived from Kenneth M. Guthrie's book, <u>Process Plant Estimating, Evaluation and Control</u>. Using Guthrie's procedure, the cost of the boilers used in each of the industries can be estimated. Table 32 gives cost estimates for these boilers.

Guthrie's book also outlines a procedure for estimating costs of industrial electric power generating facilities. Figure 34 is a plot of facility cost versus required electrical capacity in kilowatts. In Case 2, the potential electric generating capacity would be significantly greater than that actually produced because much of the useful steam is extracted for use in the industry processes. Thus, the amount of electricity generated does not reflect the actual size of the unit. The cost of the

BY KMG	TIME 1970	**FIELD ERECTED BOILER PLANT COSTS** Consult this data as a guide to costs for major steam generating facilities above 100,000 lb/hr. Field Erected Boiler Plants.
EXPONENT	0.80	
TIME BASE	MID 1970	

REQUIRED:

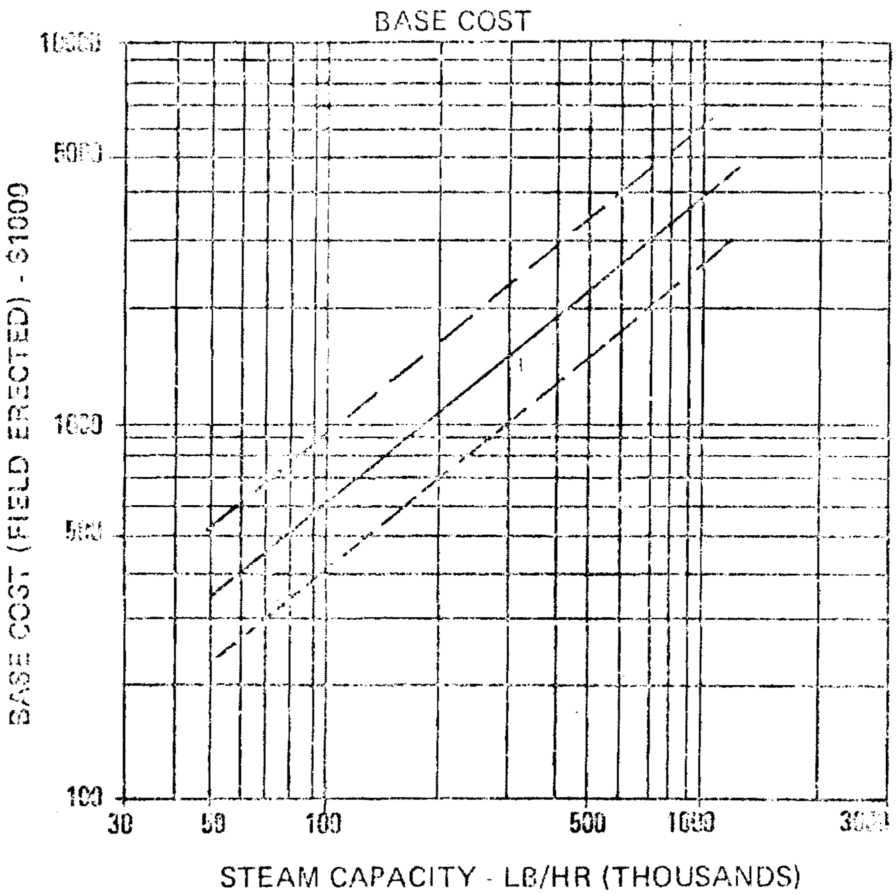
Generating capacity (lb/hr)
Steam pressure (psig)
Superheat °F

INCLUDED:

All material, FD fans, instruments, controls, burners, soot blowers; etc.
Feedwater deaerator
Boiler feed pumps
Chem. injection system
Structural steel and platforms.
Gas and oil firing.
Stack
Subcontract labor and indirects.

BASIS OF CHART

Saturated steam



BOILER PLANT MODULE COST $ = [Base cost x (F_p + F_s)] x Escalation Index

ADJUSTMENT FACTORS:

STEAM PRESSURE	F_p
Up to 400 lb.	1.00
500 lb.	1.05
600 lb.	1.08
700 lb.	1.18
1000 lb.	1.35
3000 lb.	1.58

SUPERHEAT	F_s*
Sat	0.00
100 F.	0.09
200 F.	0.18
250 F.	0.19
300 F.	0.22
400 F.	0.28

Note: If these factors are used individually add 1.00 to the above values.

Figure 33. Cost Estimating Procedure for Industrial Boilers

Source: Kenneth M. Guthrie, Process Plant Estimating and Control, 1974, p. 336.

Table 32: Estimated Cost of Industrial Power Plants
(in millions of dollars)

	Case 1 Conventional Boilers ($ 1970)	Case 2 By Product Power Plants ($ 1970)	Case 3 None Required
Chlorine-Caustic	$ .380	$10.001	--
Ammonia	$ .581	$ 9.263	--
Pulp and Paper a)	$ .336	$19.468	--
b)	$ .460		
c)	$ .310		
Phosphoric Acid	$ .160	$ 4.058	--
TOTAL	$2.227	$42.790	0
Estimated Cost in 1985 $ (5% annual increase)	$4.630	$88.957	0
Estimated Operation and Maintenance Costs in 1985 (4% of Capital Costs)	$ .232	$ 4.448	0

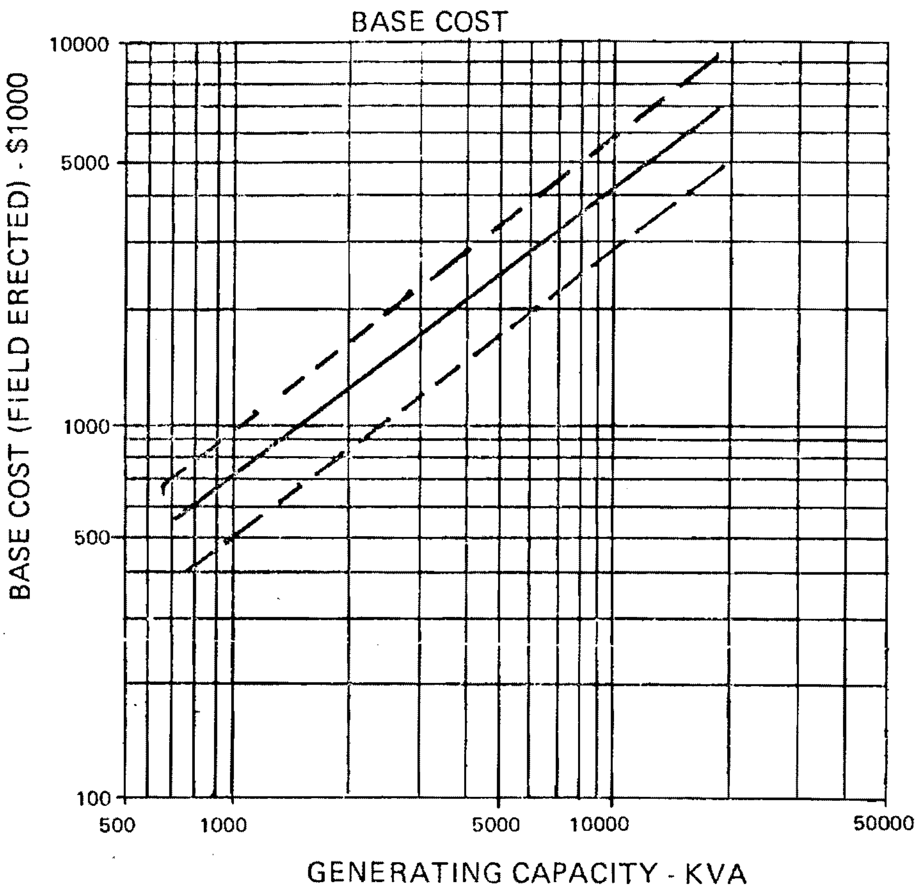
COST DATA SHEET

OFFSITE FACILITIES
POWER GENERATION

BY KMG	TIME 1970	**POWER GENERATING FACILITY COSTS** Consult this data to quickly evaluate field erected costs for turbo-generating facilities.
EXPONENT	0.75	
TIME BASE	MID 1970	

REQUIRED:
Capacity (kilowatts)

INCLUDED:
Steam generating facilities
Turbo-generating units
Field installation
Subcontractors indirects



ELECTRICAL GENERATING FACILITIES MODULE COST $ = [Base cost] x Escalation Index

INSTALLATION FACTORS (at $100,000 mag)

Material component	1.128
Labor component	0.156
Direct cost factor	1.284
Module factor	1.462

Figure 34. Capital Cost of Industrial Electric Generation Facilities

Source: Kenneth M. Guthrie, Process Plant Estimating and Control, p. 338.

unit is based on the potential quantity of electricity generated. This cost must then be corrected by subtracting the cost of the electrical generating equipment not needed. In our example, it was assumed that the cost of the electrical equipment was 15%, with a .7 economy of scale factor.

The costs of insulated piping for transporting steam to the industries were estimated using Figure 35. The relationships shown by the curves were derived in the previously cited General Electric study. The piping would only be installed in Case 3; Table 33 shows the approximate cost of the needed equipment for the assumed distance to each industry.

The cost of an expanded feedwater make-up system was available only in the General Electric study. These costs were based on the price industry would charge for water make-up. The study estimated that the annual cost of demineralized water makeup was $.90 per pound of hourly makeup required. The annual cost of heat makeup was $.93 per pound of hourly makeup required. Thus, the total annual costs for makeup for Case 3 were estimated to be $4,614,000 in December 1974. Costs in 1985, if escalated at 5% annual rate, would be $7,891,000.

In Case 3, the 1091 Megawatt multi-purpose plant does not require as extensive a cooling system as usually installed in this size plant. This savings occurs due to the fact that 2.5 million lbs per hour of steam are extracted.

Cost estimates of utility power plant cooling systems were obtained from several sources, as shown in Table 34. The most extensive data was for nuclear plants, for which operating and maintenance costs had been calculated. The operation and maintenance costs for coal-fired units were the same proportion of capital costs as in the nuclear case.

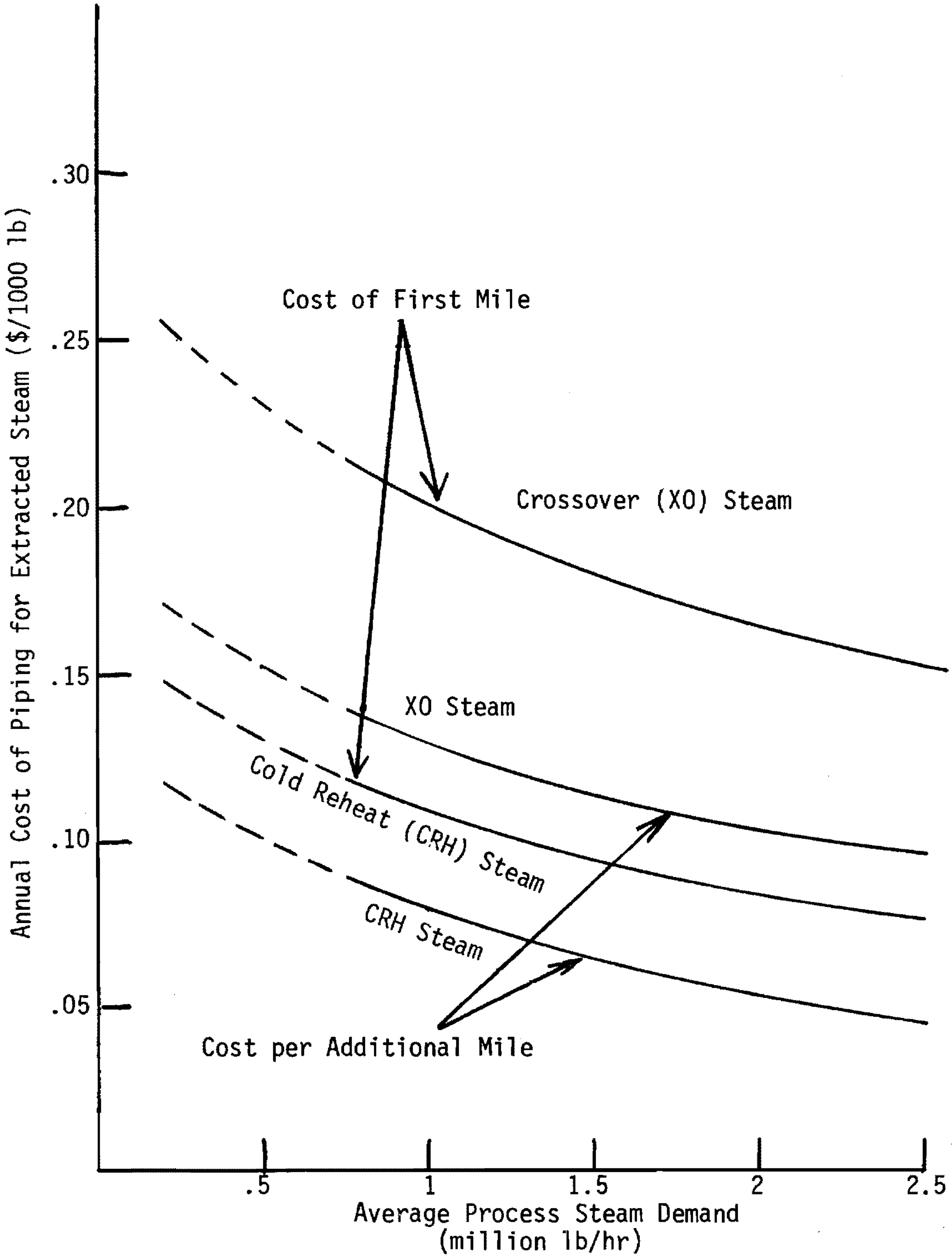


Figure 35. Piping System Fixed Costs for Case 3 (centralized option) Analysis

Source: Based in part on a General Electric Study entitled Assessment of Dispersed vs Nuclear Power Parks, p. 5-38. (Extrapolations were made by the project staff.)

Table 33: Cost Estimates for Steam Extraction and Piping Systems (Case 3)

Industry	Distance to Utility Power Plant (in miles)	Volume of Steam (1000 lb/hr)	Type of Steam[1]	Capital Cost of Piping[2] (millions of 1975 $)
Chlorine-Caustic	1.5	552.0	XO	$ 8.190
Ammonia	3.0	546.0	CRH	$ 7.953
Pulp and Paper	1.5	241.5	CRH	$ 2.188
		1,216.5	XO	$13.728
Phosphoric Acid	3.0	201.5	XO	$ 3.461
TOTAL ($million-1975)	—	—	—	$35.520
Estimated Cost in $ 1985 (5% annual increase)	—	—	—	$63.789
Operating & Maintenance Costs (assumed to be 2.5% of Capital Costs)	—	—	—	$ 1.595

[1] XO is crossover steam at 165 psia, 640°F; CRH is cold reheat steam at 500 psia, 585°F.

[2] Assumes .18 fixed charge rate using Figure G.

Table 34: Costs of Utility Power Plant Cooling Systems

	Coal Fired (1000 MW_e) Capital Cost ($million) Source 1 (1969)	Coal Fired Capital Cost Source 2 (1969)	Coal Fired Operating Cost (No Source)	Nuclear-Fired (1000 MW_e) Capital Cost ($million) Source 1 (1969)	Nuclear-Fired Capital Cost Source 2 (1969)	Nuclear-Fired Capital Cost Source 3 (1975)	Nuclear-Fired Operating Cost (mills/kwh) Source 3 (1975)
Once Through: Fresh Water							
Canal Discharge	2-3	2-5		3-5	2-5	7.78	-
Deep Discharge						8.39	-
Once Through: Sea Water							
Canal Intake & Discharge						8.53	
Deep Intake - Canal Discharge						11.30	
Deep Intake - Deep Discharge						15.30	
Evaporate Systems:							
Cooling Pond	4-6	4-10		6-9	6-12	14.50	.040
Natural Draft Towers	6-9	6-10		9-13	9-14	22.30	.187
Induced Draft Towers	5-8	5-8		8-11	8-11	15.80	.250
Dry Cooling Systems:							
Natural Draft Towers	17-21	14-25		25-32	18-11	50.20	.349
Induced Draft Towers						35.20	.5-2

Source: 1. Walter G. Belter, "Thermal Effects—A Potential Problem in Perspective", Power Generation and Environmental Change, Berkowitz and Squires, 1969.
2. William H. Steigelmann, "Alternative Technologies for Discharging Waste Heat", Power Generation and Environmental Change, Berkowitz and Squires, 1969.
3. John M. Bandel, Jr., "Opportunities for Energy Savings in the Beneficial Use of Waste Heat", The Environmental Price of Energy, Alfred Van Tassel (ed.), 1975.

The cost savings achievable in the large, multi-purpose plant can be computed as follows:

Total cost of cooling system (1985 $)	= $26.78 million
Percentage of total steam extracted for industrial use	= 22%
Estimated cooling costs savings	= $20.81 million
Operation & Maintenance cost savings	= $87,209

Operating and Maintenance Costs. A number of estimates of Operating and Maintenance (O&M) costs for utility power plants were obtained in the literature sources reviewed. A major source was the Federal Power Commission's annual publication entitled Steam Electric Plant Construction Cost and Annual Production Expenses, 1973, which contains data for most of the electric power plants in the nation. The 1973 O&M costs for plants with greater than 1000 Megawatt installed capacity that were built after 1960 are plotted in Figure 36. Those points that are starred represent southeastern power plants. Estimates found in other sources are denoted by squares. Obviously, there is no way specifically to define the operating costs of a plant. Older plants, periodically, have generally higher costs although many newer plants are exceptions to this trend. The line shown in the figure represents the assumed O&M costs, increasing at a 5% annual rate, of the utility plant used in this example. The plant is assumed to begin operation in 1985; O&M costs at this time are projected to be 2.11 mills/kwh.

O&M costs for industrial power plants were not available in the sources used for this anlaysis. It was assumed that during the first year of operation O&M costs were 5% of total capital costs. Subsequent costs were escalated at a 5% annual rate.

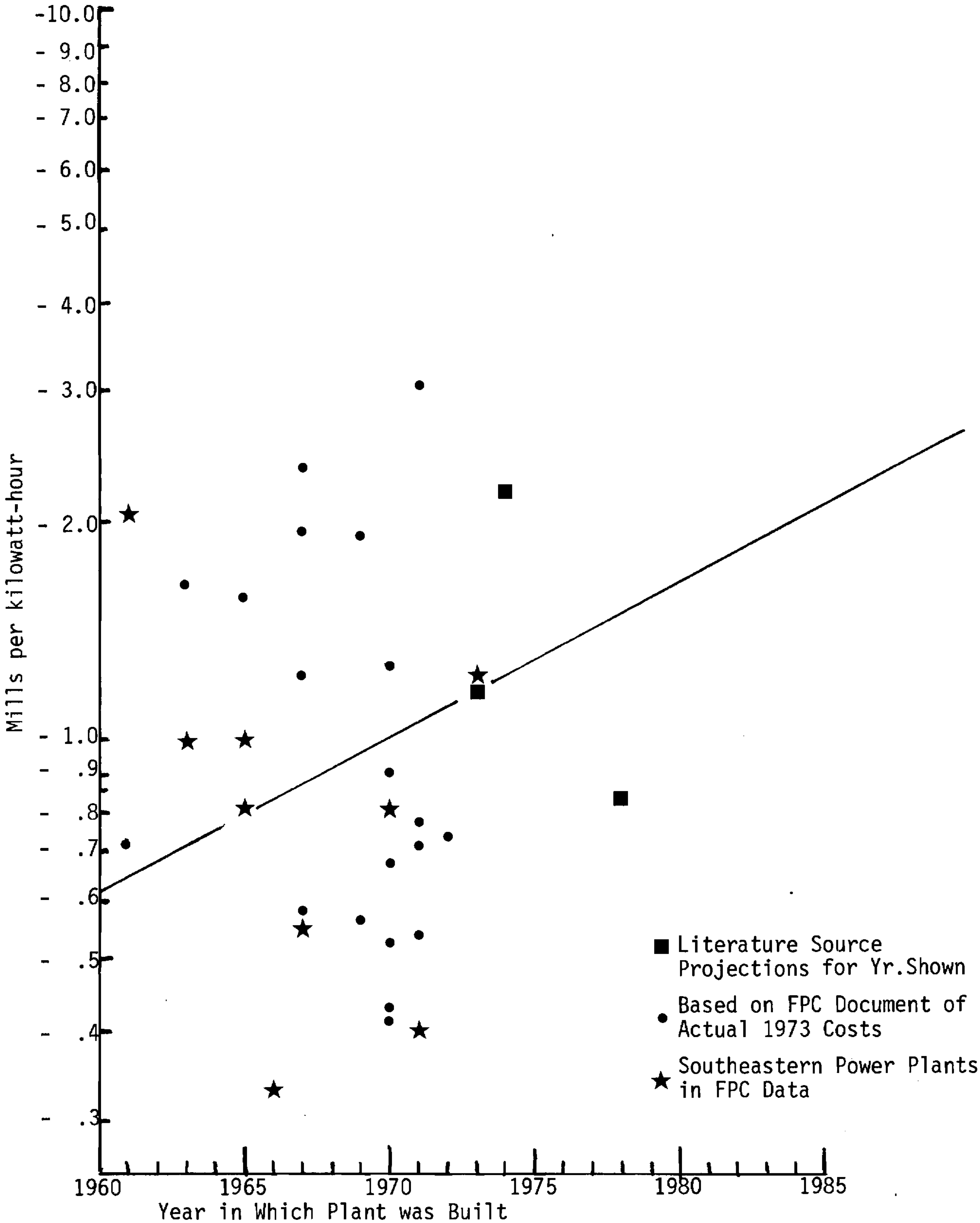


Figure 36. Operating Costs of Coal-Fired Power Plants (corrected to 1973 dollars by a 5% discount factor).

Fuel Costs. Current costs of fuel in the southeastern United States have been discussed previously (see Table 2 in Chapter II). Projecting future costs is a difficult, if not dangerous, task. Two sources were found that had made attempts. Their results are shown in Figure 37. The disparity in these projections suggests the continuation of the previous approach of using several different rates of fuel price increases. Three scenarios were defined and are described in Table 35.

Results of Analysis

Table 36 shows the estimated costs of different multiple-use systems. The costs assume that the system will begin operation in 1985. Of the three cases, the Status Quo has the lowest capital and operating costs but uses the most fuel. Case 3, the centralized option, has the highest capital and operating costs but uses much less fuel.

Table 37 shows the Net Present Value of the different systems under the three fuel cost scenarios described in Table 35. In all cases, the centralized option is the least expensive and, thus, most economically attractive. The decentralized Multiple-Use option is less expensive in Scenarios I and III but more expensive in Scenario II, where fuel oil costs increase at a low rate relative to natural gas and cool.

Both Multiple Use Systems require considerably less fuel than the Status Quo System. Case 2, the decentralized option, uses 3 trillion BTU less per year (1440 barrels of oil equivalent per day), while Case 3 uses 15 trillion BTU less annually (7200 barrels of oil equivalent per day). In terms of overall efficiency of total electrical energy and industrial steam production, the Status Quo is 49% efficient, the decentralized Multiple-Use System is 51% efficient and the centralized option is 59% efficient. The Multiple Use Systems represent 4% and 20%

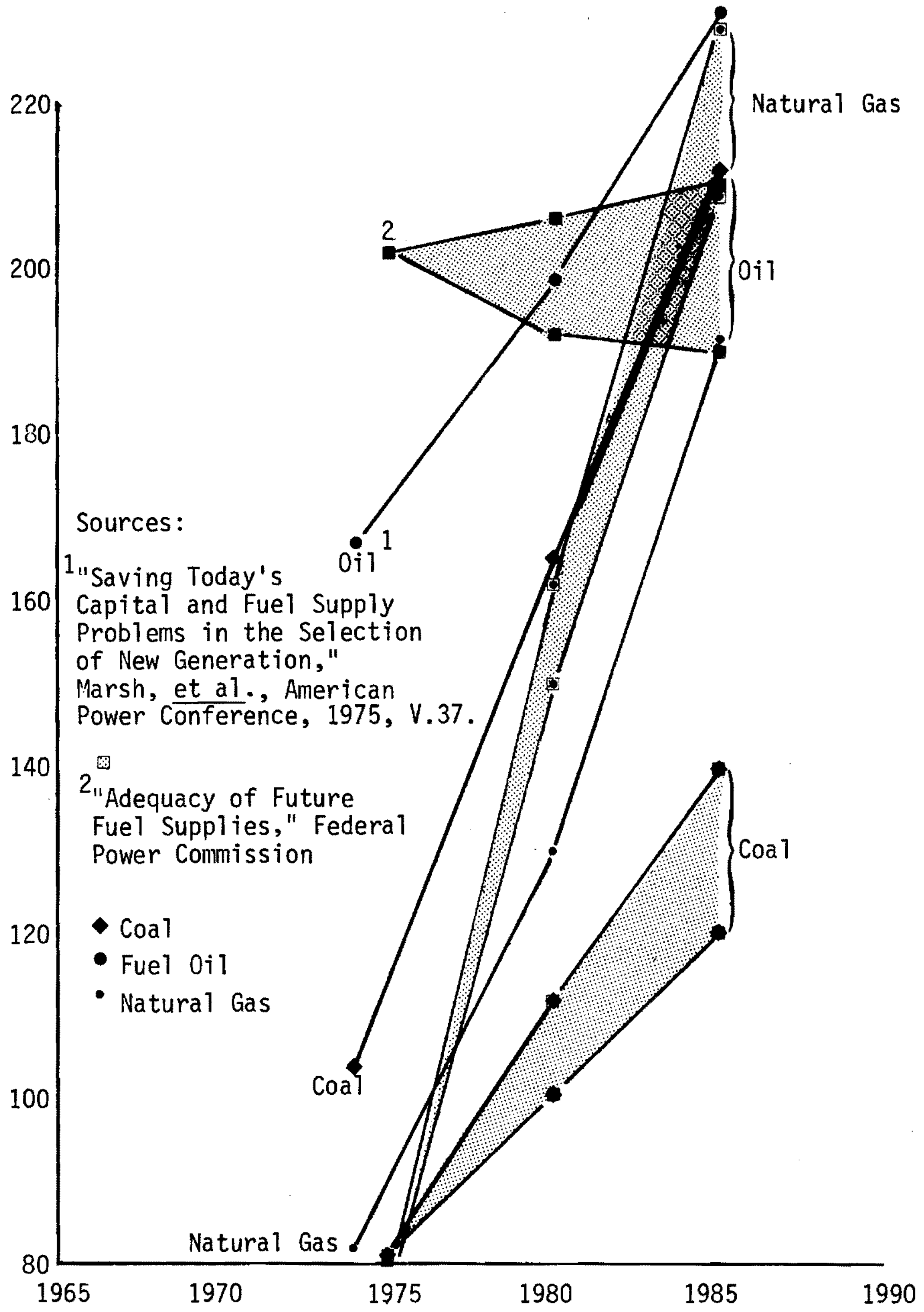


Figure 37. Projections of Utility Fuel Prices

Table 35: 1985 Fuel Costs Under Different Scenarios

	Coal		Natural Gas		Fuel Oil	
	Rate of Increase	1985 Fuel Price ($/MBTU)	Rate of Increase	1985 Fuel Price ($/MBTU)	Rate of Increase	1985 Fuel Price ($/MBTU)
Current Price (Dec. 1974 $/MBTU)	$1.04		$0.82		$1.67	
Scenario I	.08	$2.42	.09	$2.11	.06	$3.17
Scenario II	.05	$1.78	.07	$1.72	.03	$2.31
Scenario III	.05	$1.78	.05	$1.40	.03	$2.31

Table 36. Estimated 1985 Costs of Multiple-Use Systems

	Case 1*	Case 2*	Case 3*
Capital Costs ($ million)			
Utility Power Plant	692	643	736
Net Differences in Cooling Tower Costs			-3.488
Steam Extraction and Piping Systems			63.789
Industrial Power Plants	4.360	88.957	
TOTAL	696.630	731.997	796.301
Discounted at 18%	125.500	131.859	148.765
Operating & Maintenance Costs ($ million)			
Utility Power Plant (2 mills/KWH)	14.016	12.624	15.303
Cooling Tower at Utility			- .087
Feedwater Makeup for Utility			7.819
Steam Extraction and Piping Systems			1.595
Industrial Power Plants	.232	4.448	
TOTAL	14.248	17.072	24.630
Fuel Use (trillion BTU/yr)			
Coal	63.338	61.552	75.395
Fuel Oil	12.800	10.160	
Natural Gas	9.138	15.352	
TOTAL	90.276	87.064	75.395

*Case 1: Status Quo
Case 2: Decentralized Multiple Use
Case 3: Centralized Multiple Use

Table 37: Results of Analysis—Net Present Value of Each Case Under Three Scenarios (in millions of dollars)

	Present Worth Without Fuel Costs[1]	Net Present Value as Compared to Status Quo Scenario I	Scenario II	Scenario III
Case 1	-808			
Case 2	-866	34	-21	10
Case 3	-989	204	65	21

[1]Using discount rate of 18% over a 30-year life, O&M costs increase 5% annually.

increases in energy use efficiency. Perhaps an even more significant factor favoring the centralized case is that coal completely substitutes for fuel oil and natural gas. This savings of fuels facing shortages is an attractive characteristic of this option.

Conclusions and Recommendations

This study has revealed Multiple-Use Energy Systems, both centralized and decentralized, to be attractive alternatives by energy-use and economic criteria. The analysis was limited to utility/industrial complexes and considered only the energy supply systems. According to this analysis, centralized systems are favored over decentralized systems due to economy of scale savings and ability to use less expensive fuel (coal). There may be a limit to the distance over which steam is shipped that restricts the degree of centralization.

Specific recommendations of the analysis of multiple-use systems are:

- Pursue research into the following topics:
  1) Investigate for a greater number of industry combinations the economic attractiveness of different multiple-use systems.
  2) Examine environmental aspects of different multiple-use systems.
  3) Determine institutional and legal arrangements that must be made for a Multiple-Use System to be built. Identify potential barriers to implementation.
- Disseminate to both industries and utilities the potential savings derivable from Multiple-Use Systems. Encourage private research, development and design of Multiple-Use Systems and support such efforts by allowing government representatives to serve as information contacts with private industry.
- Sponsor demonstration projects of Multiple-Use Systems and advertise their successes.

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VI. CONCLUSIONS

The investigation into the economic acceptability of Hybrid-Fossil Fuel Systems and Multiple Use Systems has produced the following conclusions:

- Based on the current price of coal ($1.00/MBTU), it is not economically feasible from a national and private investor's perspective to generate electricity using a SFFHS in the southeastern United States.

- Assuming a 1% annual fuel price increase in the national welfare analysis and a 2.5% annual fuel price increase in the private investor analysis, it is economically feasible to generate electricity using a SFFHS in Miami, Florida, primarily due to the high cost of coal ($1.09/MBTU) coupled with the high solar insolation and annual hours of sunshine in this region.

- Assuming a 2.5% annual fuel price increase, it is economically feasible from a national perspective to generate electricity using a SFFHS in Miami, Atlanta, Raleigh and Charleston. It is still not economically feasible in Nashville, primarily due to the low cost of coal ($.93/MBTU) in the region.

- Based on the sensitivity analysis the price of fuel need only rise to $1.32/MBTU in the national welfare analysis ($1/69/ MBTU in the private investor analysis) for the SFFHS to yield a 7% return on investment (a 12.5% ROI in the private sector).

- In cases of relatively high landfill costs and relatively close proximity to an adequate power plant for pulverized waste combustion, a WFFHS would yield significant benefits, from a societal viewpoint.

- In almost all cases, a WFFHS would not yield an acceptable Return on Investment to a private investor.

- Development of aluminum and glass recovery techniques would add significantly to the attractiveness of WFFHS. Future shortages of aluminum would add significantly to its value and, thus, to the economic favorability of WFFHS.

- A WFFHS produces significant energy savings. In our analysis the original energy investment is repaid in less than one year.

- Pyrolysis, methanation and other large scale waste processing alternatives are not economically competitive with pulverized waste combustion. Environmental, maintenance, transportation, and storage problems of the utility, however, make these more attractive from a convenience standpoint. Environmental problems of the waste processing techniques, especially pyrolysis, may threaten their feasibility.

- In cases where the societal Net Present Value is positive and the private Net Present Value is negative, policies may be instituted to encourage private investment. A number of policies have been identified for the WFFHS.

- Multiple-Use Energy Systems, both centralized and decentralized, are attractive alternatives by energy-use and economic criteria. The analysis was limited to utility/industrial complexes and considered only the energy supply systems. According to this analysis, centralized systems are favored over decentralized systems due to economy of scale and ability to substitute steam generated from coal combustion for that generated from fuel oil or natural gas combustion. There may be a limit to the distance over which steam is shipped that restricts the degree of centralization.

VII. RECOMMENDATIONS

Recommendations of the study team based on their analysis of Fossil Hybrid Systems are as follows:

- At present, the solar energy data that is recorded is total (direct plus diffuse) insolation on a horizontal surface. Calculations need to include the total direct insolation on surfaces tracking the sun, since these are more efficient and used in high temperature systems. If the model used these figures, the economic analysis would have improved.

- Since the model is very sensitive to the price of fuel, it is extremely important that a dynamic (rather than a static) model be constructed. In this type of model different forecasts for fuel prices would be used to show the relationship between fuel prices and the feasibility of a SFFHS. This was partially done by the sensitivity analysis.

- Research needs to be pursued to lower the cost of the collectors as the model is also sensitive to this variable.

- Identify those communities where waste disposal may be a severe problem in the future.

- In cases in which the benefits of WFFHS outweigh the costs, propose and evaluate policy measures needed to give incentive for construction of WFFHS. Of course, municipal ownership is an alternative to private development, but federal government support, both technical and financial, may be needed.

- A thorough evaluation of the institutional problems associated with WFFHS development should be undertaken. A number of different actions taken by diverse groups can block implementation of this type of system. In many cases, these actions may impede a project that is in the public interest. Avenues that can be taken to overcome these institutional constraints should be developed and disseminated.

- Accurate and standardized data collection and accounting procedures are needed in solid waste disposal sections of local governments. Planning departments should be developed to perceive potential future problems (e.g., shortages of landfill space) and to propose solutions (e.g., WFFHS, Source Separation).

- Unresolved technical questions, particularly those relating to the effects of solid waste fuel combustion on boiler tube corrosion and air emissions should be addressed. Information as to their resolution should be disseminated widely.

Specific recommendations of the analysis of Multiple-Use Systems are:

- Pursue research into the following topics:
  1) Investigate for a greater number of industry combinations the economic attractiveness of different multiple-use systems.
  2) Examine environmental aspects of different multiple-use systems.
  3) Determine institutional and legal arrangements that must be made for a Multiple-Use System to be built. Identify potential barriers to implementation.

- Disseminate to both industries and utilities the potential savings derivable from Multiple-Use Systems. Encourage private research, development and design of Multiple-Use Systems and support such efforts by allowing government representatives to serve as information contacts with private industry.

  Sponsor demonstration projects of Multiple-Use Systems and advertise their successes.

APPENDICES

APPENDIX A

List of Working Papers

NOTES:

1. Working papers typically are informal documents which present points of view for discussion and research planning. Conclusions expressed in these papers should be considered tentative; recommendations expressed should be taken as possible recommendations.

2. Requests for copies of the working papers should be addressed to Dr. Jack M. Spurlock, Applied Sciences Laboratory, Engineering Experiment Station, Georgia Institute of Technology, Atlanta, Georgia 30332. Requests should reference Project B-445.

3. Authors listed are the principal authors; many of the papers include multiple contributions.

Title and Author

No.

I. Regression Study of Solar Radiation and Electrical Energy Consumption
J. S. Tiller

II. The Impacts of Regulation on Emerging Power Options
Dr. F. A. Tarpley

III. Review of Power Generation and Transmission Planning Models
Dr. B. Lin

IV. Air Pollution Costs of Fossil Fuel Electric Power Plants
S. W. Day

V. Environmental and Social Cost Issues Surrounding the Usage of Solar Energy and Solid Waste as Fuel Sources for Electric Power Generation
S. W. Day

VI. Available Capacity in Southeastern States
T. S. Blackstock

VII. Utility and Risk Aversion
Dr. F. A. Tarpley and Dr. F. E. Williams

APPENDIX B

Glossary

COST: What must be given up to acquire or achieve something. Costs to individuals are often different from costs to society. This occurs when transfer payments or externalities are involved. Examples: Buying a used car is a cost to an individual but is not a cost to society since the transaction represents the transfer payment.

Operating a car is a greater cost to society than to the individual since pollution is created. This is an external diseconomy.

COST-BENEFIT ANALYSIS (CBA): A systematic evaluation of a project to determine whether, and to what extent, its social benefits outweigh its social costs. Also, the various techniques used to perform the evaluation, such as shadow pricing and discounting. CBA draws heavily on the concepts and methods of economics.

DIRECT EFFECTS: Increased real value of output or real cost associated with a project.

DISCOUNT RATE: Given some benefit (or loss) which will be incurred at some specified date in the future, the number which, when the future benefit (or loss) is discounted by that amount, makes that benefit (or loss) comparable to one incurred in the present. The number is usually specified as an annual rate. Example: Suppose $100 is expected to be received immediately. If the discount rate is 10%, 10% x $100 = $10 means the $100 now is comparable to $110 one year from now.

EXTERNALITY: A factor which causes an individual or firm to become better or worse off, but over which that individual or firm has no control, and for which that individual or firm can be charged no fee (in the case of an external diseconomy). Pollution is an often cited external diseconomy.

INDIRECT EFFECTS: The impact of a project on the rest of the economy. Indirect or secondary benefits are a form of external benefits. Their inclusion in cost-benefit analyses has been subject to violent attack in recent years. The logic of counting these benefits should be carefully constructed and justified in terms of the objectives of a project.

NET PRESENT VALUE: A single number representing the value of a future stream of benefits and costs discounted to the present.

SCENARIO: An outline or synopsis indicating scenes, characters, plot, etc. This term has been adopted from theater use to dramatize the need for establishing and visualizing clearly the detailed nature of a project alternative.

SENSITIVITY ANALYSIS: Given some relation $A = F(P_1, P_2, \ldots, P_n)$, where the P's are parameters, the determination of the responsiveness in A to changes in the parameters. This is an important aspect of cost-benefit analysis since values for some parameters must often be crudely estimated. This allows the analyst to determine how sensitive his conclusions are to his choices of parameter values.

SOCIAL IMPACT ANALYSIS: The attempt to identify all the significant direct and indirect effects of a proposed action on man's economic, social, cultural, political, and physical environment. The analysis attempts to assess the magnitude of each impact and its value. Through the process of valuation, an attempt is made to determine, as far as possible, whether the overall effect of the proposed action is socially favorable or not. SIA also attempts to determine how detrimental effects can be circumvented. The analysis is an aid to the decision maker and should present as much information as possible in a digestable and useful format. Care must always be exercised to accurately convey the reliability limits of the analysis.

SOCIAL RATE OF TIME PREFERENCE: The discount rate at which society as a whole is willing to give up present consumption for future consumption. Although it cannot be observed in economic data and must be approximated, it is generally considered the correct rate for use in cost-benefit analysis.